BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) for a Certificate of Public Convenience and Necessity Authorizing the Construction of the Jefferson-Martin 230 kV Transmission Project	Application No. A-02-09-043

OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR

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In accordance with Rule 75 of the Commission's Rules of Practice and Procedure, the California Independent System Operator ("CAISO") respectfully submits its opening brief in the above-captioned proceeding. This proceeding was initiated to address Pacific Gas and Electric Company's ("PG&E") application for a certificate of public convenience and necessity ("CPCN"), pursuant to Public Utilities Code section 1001, et seq., to construct a new single-circuit 230kV electric transmission line between the Jefferson Substation in Redwood City and the Martin Substation in the City of Brisbane ("JM Project"). The CAISO's opening brief focuses solely on the question of the need and timing for the JM Project, not issues relating to project routing and other environmental, social, or aesthetic concerns. In this regard, the CAISO has found the JM Project will be needed by 2006 to meet applicable reliability criteria and, therefore, urges the Commission to expeditiously grant PG&E's application.

I. INTRODUCTION AND SUMMARY

The San Francisco Peninsula Area[1] constitutes a "'critical grid reliability risk area' because of limited transmission capacity into the area combined with aging energy resources within the area."[2] Following the December 18, 1998, blackout that darkened most of the City of San Francisco and nearby communities, the CAISO and stakeholders engaged in an extensive evaluation of potential options to address the inadequacies of the existing transmission system. The JM Project was selected as the preferred transmission solution on the bases of cost-effectiveness, ability to meet the load serving capability needs of the San Francisco Peninsula Area, as well as ability to reduce the likelihood of future catastrophic outages by diversifying the transmission system. (Exhibit 73 at pp.2-3, 7, 70-73; Exhibit 4, Attachments 2 and 3.) The CAISO and PG&E have established independently that the JM Project is needed by 2006 to ensure that the transmission system serving electric load within the San Francisco Peninsula Area continues to comply with applicable reliability criteria.

Intervenors do not seriously debate the need to increase the load serving capability of the San Francisco Peninsula Area. The Office of Ratepayer Advocates

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[1] The geographical area studied by the CAISO and PG&E differ. (Exhibit 39 at 15:19-20.) PG&E's testimony generally refers to the "Project Area," which consists of the City and County of San Francisco, Burlingame, Millbrae, San Bruno, South San Francisco, Brisbane, Colma, Daly City, Pacifica and Hillsborough. (Exhibit 4 at 1:10-12; Tr. at 385:22-26.) In contrast, the CAISO refers to the broader San Francisco Peninsula Area, which encompasses the San Francisco peninsula and the City and County of San Francisco. The San Francisco peninsula represents the area north of the Ravenswood Substation, which is located near the western terminus of the Dumbarton Bridge, up to the City of San Francisco. (Exhibit 4, Attachment 6 at p. 12; see also Exhibit 167.) The CAISO adopted this perspective because the ability to serve electric load within the San Francisco Peninsula Area is impacted not only by generation and transmission facilities within the San Francisco Peninsula Area, but also by transmission facilities connecting it to the greater Bay Area. (Exhibit 4, Attachment 6 at p. 12; Exhibit 38 at 3:6-15 and 8:3-21.) The different geographic scope does not create any conflict between the conclusions reached or methodologies used by PG&E and the CAISO.

[2] *Interim Opinion on 2003 Statewide/Utility Local Energy Efficiency Programs and Other Studies,* D.03-04-055 (April 17, 2003).

("ORA") succinctly confirmed that "some type of resource addition will be needed in order to increase the load serving capability to the Project area by 2006 … even under [PG&E's] low load forecast scenario." (Exhibit 46 at 4:16-21.) Rather, the debate surrounding the project centers on the question of when the JM Project will be needed and whether consideration of other alternatives may postpone the need for the project until additional information clarifies the conditions likely to prevail in the San Francisco Peninsula Area. These other alternatives revolve around the generation supply assumptions underlying the need assessment and, in particular, the inclusion or exclusion of the combustion turbines owned by the City and County of San Francisco ("CCSF CTs") and the future treatment of Hunters Point Units 1 and 4. However, this debate is superfluous for two fundamental reasons.

First, Commission precedent, CAISO Planning Standards Committee guidelines, and prudent transmission planning practices all reject assembling a supply forecast that includes an assumption the CCSF CTs will be online by 2005. The City of San Francisco's own witness admits the "outcome [of the CCSF CT project] is far from certain." (Exhibit 84 at 5:11.) No evidence has been advanced to rebut this uncertainty or, more importantly, to justify the Commission's exposing electricity customers in the San Francisco Peninsula Area to mounting reliability concerns on the basis of conjecture. When the CCSF CTs are properly excluded from the supply forecast, the Commission's options become clear – it must either approve the JM Project or rely on the continued operation of the Hunters Point Power Plant indefinitely in contravention of sound fiscal decision-making, prudent utility planning, and the Commission-approved 1998 agreement between PG&E and San Francisco to expeditiously close the power plant.

Second, even assuming the Commission violates its own precedent and CAISO guidelines by including the CCSF CTs in the supply forecast, the need for the JM Project is not eliminated, but merely deferred. ORA, for instance, estimates the JM Project will nevertheless be needed around 2008. (Exhibit 46 at 7:19-23, 8:19-20.) Accordingly, the Commission must decide whether it is willing to expose the San Francisco Peninsula Area to increased risks of outages by assuming the CCSF CTs can be sited, permitted, and constructed over public opposition by 2005 simply to avoid incurring the costs of the JM Project, at most, a couple years prematurely. The CAISO believes the correct decision is to presently grant the JM Project CPCN approval for several reasons: (1) the need to reapply for the CPCN almost immediately for a 2008/2009 in-service date wastes Commission and consumer resources, (2) a 2008/2009 in-service date is well within an appropriate planning horizon, (3) no evidence has been presented that any potential cost savings from deferral would not be offset by increased construction costs at a later date, (4) evidence has been offered that the presence of the JM Project would lead to reduced costs of and reduced pollution from local in-city generation,[3] and (5) the presence of any other reliability solution (i.e. generation, transmission, or demand-side management) addressing the supply-demand gap within the timeframe of the need for the JM Project is mere speculation.

Finally, the CAISO urges the Commission to appropriately recognize the CAISO's expertise and responsibilities for transmission planning by giving due regard in this CPCN proceeding to the CAISO's prior determinations that the JM Project is needed by 2006. This result is required under law and, as recently recognized by the

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[3] Exhibit 84 at 8:6-10.

Commission, sound public policy.[4] Accordingly, the CAISO respectfully requests that the Commission grant PG&E a CPCN to construct the JM Project.

II. THE CAISO HAS DETERMINED THE JM PROJECT IS NEEDED BY 2006

A. The JM Project Was Selected By Stakeholders Through The CAISO's Coordinated Grid Planning Process and Approved By the CAISO Governing Board

In response to the 1998 blackout, the CAISO initiated a coordinated stakeholder study process to develop a long-term transmission plan to assure that the future electric needs of the San Francisco Peninsula Area can be reliably served. The CAISO stakeholder group included a variety of entities such as the City and County of San Francisco ("San Francisco" or the "City"), PG&E, this Commission, the California Energy Commission ("CEC"), generation developers, citizen groups (i.e., Golden Gate University Environmental Law & Justice Clinic), and local governments (i.e., San Mateo County and City of Palo Alto). (Exhibit 73 at pp. 84-85.) The results of the stakeholder process are documented in the San Francisco Long Term Study Report, dated October 24, 2000 ("SF LT Study"). (Exhibit 73.)

The SF LT Study conducted power flow studies for the summer and fall of 2004 and 2009 to evaluate the adequacy of the existing transmission system. The applicable reliability criteria included both the CAISO Grid Planning Standards and the Supplementary Guide for Application of the Criteria for San Francisco ("Supplementary Guide"). (Exhibit 73 at 15.) The loads modeled in the power flow cases represented

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[4] See, *Order Instituting Rulemaking on Policies and Practices for the Commission's Transmission Assessment Process,* R.04-01-026 (Jan.22, 2004) [deferring to the CAISO's need determinations based on a Commission-adopted methodology "is an improvement over historic practices and processes in that it leverages existing expertise at the Commission and CAISO, and facilitates an improved, streamlined, and more comprehensive approach toward transmission planning."].

peak load conditions and presented a maximum anticipated coincident peak load for the San Francisco Bay Area based upon 1-in-10-year adverse weather conditions. (*Id.* at 17-20.) Supply was evaluated at 2000 existing levels as well as plus/minus 400 MW to approximately account for the then-proposed addition of new generation at the Potrero Power Plant and the agreed-upon closure of Hunters Point Power Plant. (*Id.* at 21.) In addition, to account for uncertainty, various sensitivities were run to evaluate the effect of an increase or decrease in forecasted load of 10 percent. (*Id.*) The SF LT Study concluded, "without new transmission or generation facilities, system performance would be unacceptable." (*Id.* at 2.)

The SF LT Study then evaluated potential solutions to address the system's deficiencies, including generation, transmission, and load reduction. Load reduction was rejected as a viable solution "due to the magnitude of load reduction that would be required." Generation and transmission were considered effective solutions. Six potential transmission projects were evaluated: (1) Jefferson-Martin 230kV, (2) Jefferson-Hunters Point 230kV, (3) Jefferson-Potrero 230kV, (4) San Mateo-Martin 230kV, (5) Moraga-Potrero 230kV and (6) San Mateo-Martin #4 60kV to 115kV conversion. (*Id.* at 2.) The projects were compared based on their ability to meet applicable reliability criteria, project cost, level of permitting required, sensitivity to environmental justice, and system losses. Based on these factors, the Jefferson-Martin 230kV line was selected over the San Mateo-Martin option largely on incremental reliability benefits resulting from additional diversification of the transmission grid. (*Id.* at 7 and 71-77.) The SF LT Study further recognized that "a combination of this 230kV and the conversion of the existing San Mateo-Martin 60kV line to 115kV operation could

eliminate the need for the Hunters Point Power Plant at least until 2009 which was the latest year studied." (*Id.* at 3.)

Therefore, in October 2000, based on the recommendations of the CAISO stakeholder group, the CAISO recommended to the CAISO Board of Governors that the JM Project be approved as the preferred long-term transmission alternative to address the identified reliability concerns in the San Francisco Peninsula Area. (Exhibit 38 at 12:6-13.) The Board of Governors approved the project without regard to routing. (Exhibit 4, Attachment 2.) Thereafter, based on updated load, cost, and supply forecasts, the CAISO Board of Governors in April 2002 again concluded that the JM Project was needed and granted final approval to PG&E. (Exhibit 38 at 12:24-13:1.)

B. The CAISO's San Francisco Load Serving Capability Study/Testimony Confirms the Need for and Benefits from the JM Project

In 2002, the CAISO concluded that an independent analysis of the San Francisco Peninsula Area transmission system was needed to provide a comprehensive determination of the maximum load serving capability under a multitude of future generation and transmission scenarios. The result was the San Francisco Load Serving Capability Study, dated July 10, 2003 ("SF LSC Study"). (Exhibit 155.) Load serving capability is the amount of demand that can be served in a particular area based on the electrical transmission system and available generation within that area, without violating CAISO reliability criteria. As such, the SF LSC Study describes how much electric load within the San Francisco Peninsula Area can be served under different transmission reinforcement and generation scenarios. The SF LSC Study approach decouples and insulates the results from load forecasts and simply identifies at what load level a

violation of the reliability criteria would occur assuming certain generation dispatch and transmission configurations exist. (Exhibit 38 at 7:15-22; Exhibit 39 at 8:11-9:2.)

The ability to serve load in the San Francisco Peninsula Area rests on the capability of the interconnected transmission system to deliver the necessary power not served by local generation. If the transmission system supplying power to the San Francisco Peninsula Area is constrained, then the ability to serve load in that area will be limited by those constraints. Furthermore, transmission constraints downstream will limit load serving capability regardless of the capability of the transmission system closer to the load. (Exhibit 38 at 8:27-9:5.) For this reason, the SF LSC Study focused on the entire San Francisco Peninsula Area, not just the Project Area as defined by PG&E, so that all constraints serving load could be identified and mitigation alternatives developed. (*Id.* at 9:7-13.) No party or intervenor has challenged the validity of the SF LSC Study methodology.

Using the SF LSC Study approach, the CAISO's testimony in this proceeding evaluated the load serving capability of the San Francisco Peninsula Area with and without the JM Project. The CAISO's analysis employs two parameters: (1) that PG&E completes all CAISO approved transmission projects currently included in PG&E's annual expansion plan submitted to the CAISO for 2003 and (2) Hunters Point Unit 4 and Unit 1 are retired. (Exhibit 38 at 10:12-20.) As in the SF LSC Study, the system conditions modeled by the CAISO in its testimony include the following completed or anticipated transmission upgrades and local generation:

- Tesla-Newark 230 kV line rerate
- Newark-Ravenswood 230 kV line rerate

- Ravenswood-San Mateo 115 kV line rerate
- Monta Vista-Jefferson 1&2 230 kV line rerate
- Ravenswood-San Mateo 230 kV line reinforcement project
- New 230/115 kV transformer bank at Ravenswood substation
- New 115 kV cable from Potrero-Hunters Point in the City of San Francisco
- San Mateo-Martin 60 to 115 kV conversion project
- Retirement of Hunters Point Units 1 & 4

In addition, the analysis set forth in the CAISO testimony also models the following projects proposed by PG&E through the 2003 Expansion Planning process:

- Tesla-Newark 230 kV reinforcement project
- Ravenswood-Ames 115 kV reinforcement and Newark-Ames 115 kV line rerate project

(Exhibit 163; Exhibit 155.)

The analysis in the CAISO testimony, therefore, updates the cases modeled in the final SF LSC Study by including the Tesla-Newark 230 kV bundling project and the Newark-Ravenswood-Ames 115kV line project. (Exhibit 165, Attachments 1 and 2.) Based on these updates, parameters, and applying the CAISO Grid Planning Standards discussed further below, the CAISO determined that the load serving capability for the San Francisco Peninsula Area without the JM Project will be limited to 1862 MW.

(Exhibit 38:3-20-24 and 10:11-20.) Building the JM Project will increase the San Francisco load serving capability to 2092 MW. (Exhibit 38:3:23-24.[5])

The need for the JM Project can be established in a straightforward manner by applying a load forecast to the CAISO's load serving capability number. In March 2003, PG&E released to the CAISO and stakeholders a load forecast for the larger San Francisco Peninsula Area using its "March 2003 low load forecast" methodology with 2006 load projected to be 1,949 MW. (Exhibit 4 at 65:11-13; Exhibit 163, Appendix 1.) This forecast exceeds the load serving capability of the San Francisco Peninsula Area without the JM Project. Therefore, based on PG&E's conservative low load forecast, the JM Project is needed by the end of 2005 to ensure that the projected load can be reliably served.

C. The Reliability Criteria Was Properly Applied by the CAISO

As summarized by PG&E:

> To determine whether the Jefferson-Martin Project is needed and by what date, a power flow scenario is needed to test whether the energy supply that is forecast will reliably meet demand for energy. For a system to reliably meet demand, it must not only meet demand under normal operating conditions, but must also meet demand under various criteria that assume outages of various components of the system in a power flow case. Therefore, the system's capability is determined by measuring the system's performance and robustness against the applied reliability criteria at forecast load demand. (Exhibit 4 at 68:4-10.)

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[5] The tables set forth in Attachments 1 and 2 to Exhibit 165 represent the results of powerflow studies with and without the JM Project holding all other available generation and transmission system resources constant, which show the constraints associated with different load levels within the San Francisco Peninsula Area. Within each table, the limitation is highlighted in bold. Any potential limitations above the bold line were resolved either with an assumed transmission system reinforcement project or were not a limitation relevant to serving load within the San Francisco Peninsula Area. For each line or limitation shown within the tables, outages of all transmission facilities within the San Francisco Peninsula Area and the lines across the bay were taken to identify the most limiting outage for that load level.

Throughout the proceeding, 280 Corridor has attempted to engender confusion and debate regarding the appropriate application of the CAISO's Grid Planning Standards or reliability criteria to the JM Project. Its arguments are twofold. First, 280 Corridor advocates replacing the CAISO's reliability criteria with some undefined "probabilistic" reliability criteria by attempting to show arithmetically the low probability of certain contingency events. (Exhibit 100 at 25; Exhibit 101 at 7.) Second, 280 implies that use of PG&E's Supplementary Guide conflicts with the CAISO's Planning Standards and results in unnecessarily "stringent" criteria being applied. Neither contention has merit and should be ignored.

1. The CAISO's Grid Planning Standards Do Not Permit PG&E to Employ Probabilistic Standards

280 Corridor's plea for application of probabilistic reliability criteria ignores that the CAISO and PG&E are required to utilize reliability criteria that is deterministic in nature. California Public Utilities Code section 345 provides that the CAISO "shall ensure efficient use and operation of the transmission grid consistent with achievement of planning … criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council." In compliance with statute, the CAISO has adopted reliability criteria that incorporate North America Reliability Council ("NERC") and Western Electricity Coordinating Counsel ("WECC" - successor to the Western Systems Coordinating Council) as well as its own Planning Standards, which build off of, rather than duplicate, the NERC and WECC standards. These standards together compose the "Applicable Reliability Criteria" under

the CAISO Tariff approved by the Federal Energy Regulatory Commission.[6] The CAISO Tariff further specifies that the CAISO and Participating Transmission Owners ("PTOs"), including PG&E, must ensure system reliability consistent with Applicable Reliability Standards and that each PTO must develop an annual transmission expansion plan to meet that goal.[7]

The NERC/WECC/CAISO planning standards are deterministic, not probabilistic, in nature. The Applicable Reliability Standards set forth fixed boundaries that limit the extent or scope of allowable system performance resulting from expected events that occur on the power system. The planning standards are defined by allowable system performance levels (A, B, C, or D) that result from a specific system element or multiple elements being forced out of service by some unknown event. Category A defines the "base case" and requires that "normal ratings of equipment will not be exceeded with all generators, lines, and transformers in service." (Exhibit 4 at 69:6-8.) The CAISO's San Francisco Greater Bay Area Generation Outage Standard modifies the base case by specifying that three units must be removed from service before running any analysis: (1) one 50 MW CT in the Greater Bay Area but not on the San Francisco Peninsula, (2) the largest single unit on the San Francisco Peninsula, and (3) one 50 MW CT on the San Francisco Peninsula. (Exhibit 103.) Category B requires that emergency ratings of equipment will not be exceeded with the loss of a single circuit, generator, or transformer or of a single circuit and a single generator. Loss of load is not permitted under Category B, unless the CAISO Board of Governors decides that the capital project alternative is

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[6] Federally approved utility tariffs have the force and effect of a federal statute. (*Crancer v. Lowden* (1942) 315 U.S. 631, 635.)

[7] CAISO Tariff §§ 3.2.1.2 and 3.2.2.1. (http://www.caiso.com/docs/09003a6080/27/fe/09003a608027feed.pdf.)

clearly not cost effective. Under Category C, emergency ratings of equipment must not be exceeded with the loss of a single circuit, generator, or transformer, or of a single circuit and a single generator, followed by manual adjustments, and then followed by loss of another single circuit, generator, or transformer. Loss of load is allowed under Category C, unless the CAISO Board of Governors decides that the capital project is clearly cost effective (after considering all the costs and benefits). (*Id.)*

These criteria are deterministic – the system must perform under the prescribed conditions. Both the CAISO and PG&E are compelled by law to plan the grid in accordance with these deterministic reliability criteria. Since the California Legislature, which made the CAISO responsible for reliable operation of the transmission grid, determined that the WECC and NERC planning standards should be minimum standards for the CAISO and PTOs, it is reasonable to surmise that the Legislature similarly intended the Commission to view WECC and NERC planning standards as minimum standards in undertaking its responsibilities. Moreover, generally accepted probabilistic standards do not yet exist and 280 Corridor certainly does not propose any. Thus, application in this proceeding of standards different from that utilized by the CAISO and PG&E in their planning studies would lead to regulatory inefficiency and uncertainty in the industry.

2. 280 Corridor's Challenge to the Supplementary Guide is Irrelevant

Much-to-do was made over whether the Supplementary Guide imposes a more stringent standard than the CAISO's Grid Planning Standards because CAISO Category C allows for interruption of load under certain circumstances, while the Supplementary Guide does not. The purported controversy appears intended to raise two implications –

that application of the Supplementary Guide may have resulted in criteria violations where none would otherwise exist and that loss of load should be considered an alternative to the JM Project. Neither implication, however, withstands scrutiny.

With respect to the first implication, the CAISO has established that a Category B violation will occur in 2006 without reference to the outage contingencies set forth in the Supplementary Criteria. While PG&E analyzed the transmission system between Martin and San Mateo Substations in accordance with the Supplementary Criteria, the CAISO analyzed a larger study area to determine if limitations existed farther downstream that would inhibit load serving capability within the San Francisco Peninsula Area. As explained in the CAISO Rebuttal Testimony in the context of evaluating the efficacy of rerating the 115 kV lines between Martin and San Mateo Substations, the ability to serve load within the San Francisco Peninsula Area without the JM Project remains limited by an outage of the Tesla-Ravenswood 230 kV line overloading the Newark-Ravenswood 230 kV line. (Exhibit 165 at 6:21-7:14.) This result is reported in Attachment 1 to Exhibit 165. Thus, the need for the JM Project is demonstrated without reference to the Supplementary Guide or particular contingencies on the transmission system between San Mateo and Martin Substations.

With respect to the second issue of load shedding, the CAISO's Planning Standards do not allow interruption of load under Category B unless the CAISO Board of Governors finds that the capital project alternative is clearly not cost-effective. As noted above, the CAISO identified a criteria violation under Category B, where only the Tesla-Ravenswood 230kV line is modeled out of service. The presumption is therefore against load shedding and no determination was made that the JM Project was not cost effective.

Indeed, one of the criteria in selecting the JM Project was "How much would the option cost and is there risk of significant cost escalation?" (Exhibit 155 at 5 and 70.) More importantly, the CAISO Board found the JM Project to be cost-effective. (Tr. 666:10-17, 690:13-21, 691:25-693:2.) Thus, the issue regarding whether the Supplementary Guide is a more limiting application of reliability criteria because it does not allow for load shedding is immaterial.

D. The Load Forecast Used by the CAISO and PG&E is Reasonable

The CAISO's Grid Planning Standards require that transmission studies addressing local load serving concerns of the type at issue here utilize a 1-in-10-year extreme weather load level. Studies focusing on regional facilities, i.e., major interties, may use a less stringent 1-in-5-year extreme weather load level. The CAISO deemed the more rigorous local area requirement necessary "because fewer options exist during actual operation to mitigate performance concerns ... [so that] [h]aving a higher standard for local areas will help minimize the potential for interruption of end-use customers." (Exhibit 103.)

PG&E offers low, medium, and high load growth forecasts to support the need for the JM Project. Each of these forecasts complies with, and builds off of, the requirement in the CAISO Grid Planning Standards that transmission studies on a local level utilize load projections based on 1-in-10-year adverse weather conditions. The CAISO's testimony refers to the load forecasting methodology and data used in PG&E's March 2003 Electric Grid Expansion Plan study submitted, reviewed, and accepted by the CAISO and stakeholders in the CAISO's annual grid planning process. (Exhibit 38 at 3:27-28; Exhibit 4 at

65:11-18.) During the grid planning process, the CAISO independently validated the reasonableness of PG&E's load forecast using CAISO historical real-time energy data. (Exhibit 38 at 13:5-12.) The methodology and data reflected in PG&E's March 2003 Electric Grid Expansion Plan are the same used to develop PG&E's low load forecast. (Exhibit 4 at 65:11-18.) Therefore, the disparity between the load forecast numbers referenced in the CAISO's testimony for 2006 (1949 MW) and 2010 (2050 MW) and PG&E's low forecasts does not result from a difference in analytical approach, but instead can be explained by the fact that the CAISO examined the San Francisco Peninsula Area, a geographic area broader than the Project Area used by PG&E.

PG&E's low load forecast, and therefore the forecast used by the CAISO as well, represents a conservative projection "to reflect potential load growth during a period of economic downturn." (Exhibit 4 at 65:19.) The Commission should take a similarly conservative perspective by regarding the low load forecast as a minimum value subject to the greater likelihood load will exceed that threshold. This approach comports with PG&E's suggestion that the Commission "assign equal probabilities to each of the load growth scenarios" and is further warranted by the extreme volatility of load recorded by PG&E for the project area as well as evidence of increased economic growth. (Exhibit 4 at 57:1-8, 67:5-6.) Indeed, the United States Department of Commerce, Bureau of Economic Analysis, confirmed the recent acceleration of economic growth by reporting that during 2003 real gross domestic product increased 4.3 percent in comparison to

2.8 percent during 2002.[8] Giving greater weight to the higher load forecasts would reflect prudent planning principles by ensuring service is not interrupted based on an underestimation of load growth.

No party has mustered a viable challenge to PG&E's load forecasting methodology. The contentions of 280 Corridor, for example, rest on speculation and confusion. 280 Corridor concludes that because PG&E's recorded load growth from 1999 to 2003 was 46 MW, PG&E's low load forecast of 86 MW for the period from 2003 to 2007 is unreasonable. (Exhibit 100 at 20-21.) However, 280 Corridor fails to account for the sustained economic downturn that began in 2000 or the dramatic volatility observed in load. For instance, prior to the onset of the recession, between the years 1998 and 2000, the recorded load in the Project Area increased on an average of 57 MW per year, vastly in excess of the 22 MW per year growth assumed under the low load forecast. (Exhibit 15 at 18:20-28.) ORA, in fact, confirmed the reasonableness of PG&E's low load forecast by concurring "it is reasonable to assume that 25 MW of incremental LSC will be needed in each year from 2006-2008." (Exhibit 46 at 4:26-27.)

280 Corridor further concludes "a downward trend in peak load growth in the Project Area" exists based on the observation that the 46 MW increase in load growth in the Project Area from 1999 to 2003 represents an 8 MW reduction in growth from the previous five years. (Exhibit 100 at 20.) No analysis based on

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[8] The CAISO respectfully requests that the ALJ take judicial notice of the attached Department of Commerce, Bureau of Economic Analysis, report entitled "Gross Domestic Product: Fourth Quarter 2003 (Preliminary)," released February 27, 2004, pursuant to Rule 74 of the Commission's Rules of Practice and Procedure and California Evidence Code section 452(h). Evidence Code section 452(h) provides that a court may take judicial notice of "[f]acts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy." (www.bea.gov/bea/rels.htm.)

economic and demographic data or actual trends in energy conservation is offered by 280 Corridor to support this assertion. Indeed, accepting 280 Corridor's dramatic and unsupported analysis would expose the San Francisco Peninsula Area to significant reliability risks to the detriment of those 280 Corridor claims to represent.[9]

During cross-examination of PG&E witnesses, 280 Corridor also attacked PG&E's method of capturing the effects of energy efficiency, distributed generation, and demand response through an analysis of historic load levels. As explained by PG&E:

> Because the forecasting methodology is based on the econometric equations that are developed from historical data, the system demand forecast implicitly includes the results of many factors that shape the historical data, including the effects of past energy efficiency, conservation, demand response and distributed generation programs. (Exhibit 4 at 65:1-4.)

PG&E admitted that "[e]xcept for energy conservation, future programs are not explicitly included in the forecasting process." (*Id.*) PG&E's methodology is reasonable. Yet, 280 Corridor attempted to create the illusion that PG&E's methodology will materially underestimate future load reduction from demand-side programs by, for example, repeated references to goals set forth in the Electricity Resource Plan of the City of San Francisco. (Exhibit 21: Tr. at 405:2-412:24.) The goals in the Electricity Resource Plan are commendable, but wholly speculative. ORA agrees. ORA recognizes that "the supply-demand gap

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[9] 280 Corridor's confusion regarding PG&E's forecasting methodology is evident from its assertions that "PG&E added 42 megawatts to its forecasted 2003 load to account for the potential for under-forecasting of future load." (Exhibit 100 at 21.) On cross-examination Mr. Shields, 280 Corridor's witness on forecasting issues, acknowledged that his contention was incorrect because he failed to adjust the recorded peak for 2003 for the 1-in10 year weather requirement. (Tr. 1881:4-16.) In fact, Mr. Shields admitted that his reduction to the normalized results of PG&E's forecast for 2003 was not based on any forecasting methodology, but simply based on his own subjective evaluation. (Tr. 1881:22-1882:22.)

in 2006" is unlikely to be closed by energy efficiency, demand response, load management, distributed generation, or other demand-side programs," and that "new renewable generation projects such as wind, solar, and tidal energy, will not be developed in time to meet the 2006-2008 period need." (Exhibit 46 at 6:1-6.)

Moreover, 280 Corridor's selective use of the Electricity Resource Plan is intrinsically contradictory. 280 Corridor elevates, for example, the credibility of the plan's energy efficiency goals. But to be consistent, other elements of the plan should also be viewed as cogent and beneficial, including the City's support for the JM Project to achieve the goal of increased transmission capacity of 450 MW by 2006. (Exhibit 21 at 68-69.) Accordingly, the Commission should accept the results of PG&E load forecasting in determining the need for the JM Project.

E. The Supply Forecast Used By CAISO and PG&E Properly Excluded the CCSF CTs and Hunters Point Units

The need determinations of both the CAISO and PG&E properly excluded from the estimate of available supply the capacity associated with the CCSF CTs and Hunters Point Unit 1 and Unit 4.

1. CCSF CTs

The assumption that the CCSF CTs will be constructed and operational by the end of 2005 is contrary to prudent transmission planning principles, the CAISO's Planning Standards Committee guidelines for modeling new generation, and the Commission's *Valley-Rainbow* decision.[10] Under the CAISO's Grid Planning Policies and Processes, "only generation that is under construction and has a planned in-service date within the

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[10] *In the Matter of the Application of San Diego Gas & Electric Company (U 902 –E) for Certificate of Public Convenience and Necessity Valley-Rainbow 500kV Inter-Connect Project,* D.02-12-066 (Dec. 24, 2002).

time frame of the study period should be modeled in the initial power flow case." Generation that has received regulatory approval can be considered in 10-year planning cases. (Exhibit 165 at 6:3-6.) Similar to the CAISO guidelines, the Commission in *Valley-Rainbow* concluded that only "generating units that are under construction or have received regulatory permits" should be included in the resource mix for transmission planning purposes." In fact, the *Valley-Rainbow* decision made clear that the tremendous uncertainty surrounding the permitting and construction process for generation resources, coupled with the dire consequences of relying on conjecture, renders the rule unconditional. Extrinsic evidence can be considered only to demonstrate that the future of generating plants that meet the test "is in question," not to rehabilitate plants that fail to meet the standard in the first instance.[11]

It is unassailable that the CCSF CTs do not satisfy the CAISO's or the Commission's *Valley-Rainbow* standards. The CCSF CTs are not under construction. Nor has the City of San Francisco filed its Application for Certification ("AFC") with the CEC. (Exhibit 84 at 5:8-22.) Thus, the CCSF CTs must be excluded from the resource forecast.

Even if the Commission was willing to violate its *Valley-Rainbow* decision by considering other evidence, no reason exists to deviate from its precedent in this proceeding. The existence of a contract between the City of San Francisco and the California Department of Water Resources for the output of the CTs constitutes the sole factor cited by 280 Citizens and ORA to support their proposed assumption that the

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[11] *Valley-Rainbow* at p. 33 ["Standard industry practice indicates that we should include proposed generating units that are under construction or have received regulatory permits in the resource mix for transmission planning purposes unless there is compelling evidence that the future of such plants is in question" (emphasis added).]

CCSF CTs will be online by the end of 2005 when needed. (Exhibit 46 at 5: Exhibit 100 at 22-23; Tr. 908:18-909:4.) However, even CCSF, the proponent of the CT project, admits that the "outcome is far from certain." (Exhibit 84 at 5:11.) 280 Corridor and ORA discount the existence of public opposition to the CCSF CTs and its potential to smother or delay completion of the project. (See Exhibit 54 at 4; Exhibit 4 at Attachment 10.) Any delay jeopardizes the ability of the CCSF CTs to meet reliability needs when required at the end of 2005. This is especially true given that the City of San Francisco anticipates filing its AFC in March 2004, the approximate twelve-month permitting process at the CEC, and the time needed for site preparation and construction. (Exhibit 84 at 5:12-14; Exhibit 15 at 12:8; Tr. 911:14-18.) Uncertainty reigns in each of these phases to potentially disrupt an already extremely tight and optimistic schedule.

The doubt surrounding the CCSF CTs is exacerbated by the power purchase agreement itself. According to ORA, the City of San Francisco has missed a milestone under the contract between the State and the City, allowing control of the CTs to revert back to the State. (Tr. 923:25-924:13.) This was confirmed by Mr. Flynn, witness for the City of San Francisco, who testified that the State has the right to cancel the power purchase contract up until the time the City issues bonds to finance the project, which will not occur until after the AFC is granted by the CEC. (Exhibit 84 at 5:18-22.) In the end, neither 280 Corridor nor ORA could give any assurance that the CCSF CTs will be available when needed. (Tr. at 908:13-17; 1893:22-26.) Thus, based on the proper application of the CAISO Planning Standards and the *Valley-Rainbow* decision, the capacity from the CCSF CTs is irrelevant and should be ignored until construction is initiated or, at a minimum, until permitted by the CEC.

2. Hunters Point #1 and #4

In the *Valley-Rainbow* decision, the Commission stated evidence must be "sufficiently convincing" to justify removal of existing capacity from the projection of generation supply.[12] The evidence presented here satisfies this test. Through its agreement with the City of San Francisco to settle litigation brought by the City and other local citizen organizations, PG&E is obligated to "permanently shut down the Hunters Point Power Plant as soon as the facility is no longer needed to sustain electric reliability in San Francisco and the surrounding area and the Federal Energy Regulatory Commission has authorized PG&E to terminate PG&E's Reliability Must Run Contract for the facility." (Exhibit 4, Attachment 8.) The Commission consented to seeking the expeditious closure of the entire Hunters Point Power Plant by approving the agreement. (Exhibit 4 at 22:14 and fn. 41; Tr. 1843:15-18.)

The closure of Hunters Point Power Plant hinges, in part, on system reliability. Consequently, inclusion of the capacity from the Hunters Point Power Plant in the supply forecast necessarily defeats the intent and goal of the agreement. It does so through the circular effect of deceptively maintaining available capacity that serves to delay the perceived need for an alternative resource and thereby perpetuates the life of the plant. Given the clear consensus among PG&E, the City of San Francisco, and the Commission to close the entire Hunters Point Power Plant as soon as practicable, it follows that the assumptions underlying the planning and siting process should exclude the Hunters Point Power Plant capacity. Simply put, resources, such as the JM Project, are proposed to attain planning goals, which in this case includes closure of Hunters Point Power Plant. The foregoing rationale for excluding Hunters Point Power Plant endures regardless of

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[12] *Valley-Rainbow* at 24-25.

the ability of the units to operate in the near term in compliance with environmental, economic or mechanical limitations. Thus, on this basis alone, the exclusion of Hunters Point Power Plant from available existing generation is appropriate.

It is clear, however, that the capacity from Hunters Point Power Plant should also be excluded from the supply forecast based upon environmental, economic, and mechanical considerations. In *Valley-Rainbow*, as discussed further below, the Commission relied on a flexible five-year planning horizon.[13] Here, PG&E submitted its supply forecast in October 2003 and, therefore, even under the minimum five-year planning horizon, the supply forecast may be based on the expected conditions prevailing at the close of 2008. The record demonstrates that continued operation of Hunters Point Power Plant beyond the minimum planning horizon is wholly unrealistic.

Hunters Point Unit 4 is at or beyond the useful life of generating units of similar vintage and type. (Exhibit 4 at 22:14-18.) That unit is six times as likely to suffer a forced outage than the general generation portfolio in the CAISO control area, while Hunters Point Unit 1 is approximately three time as likely to be offline. (Exhibit 83 at 6, Table 1.) Based on this recent operating and maintenance history, Hunters Point will require significant and increasing investment to continue operations. (Exhibit 4 at 24:5-7.) The folly of indulging in such investment is exacerbated by the effect of increasingly stringent air quality standards adopted by the Bay Area Air Quality Management District ("BAAQMD"). Beginning in 2005, the NOx emission limit will be reduced to .018lbs/mmBtu, which equates to approximately 15 parts per million NOx. Hunters Point Unit 4 operates at .037-.044 lbs/mmBtu. (Exhibit 157.) Accordingly, for the entire

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[13] *Valley-Rainbow* at 17 ["We agree with the ISO that this planning horizon should not be mechanistically applied but rather requires the exercise of judgment, based on the facts of each project."].

Hunters Point Power Plant to continue to operate beyond January 1, 2005, the Hunters Point Plant must either undertake a significant $15 million retrofit of Unit 4 to install Selective Catalytic Reduction equipment, or obtain from BAAQMD a sufficient quantity of Interchangeable Emission Reduction Credits ("IERCs"). (Exhibit 4 at 22:19-23:7.) All IERCs available to PG&E would be consumed by 2008, and possibly earlier, if Unit 4 operates at a higher than average emission and capacity factor. (Exhibit 157.) Thus, where, as here, tangible economic, mechanical, and environmental restrictions prevent a generation resource from operating outside the planning horizon, that resource cannot, and should not, be considered in the supply forecast under Commission precedent.

III. EVEN ASSUMING THE HUNTERS POINT UNIT 1 IS ONLINE, THE JM PROJECT IS STILL NEEDED BY 2006 AND A CPCN SHOULD BE ISSUED

While the CAISO believes modeling the entire Hunters Point Plant offline is appropriate for transmission planning purposes for the reasons stated above, the CAISO has also acknowledged its approval of a "step-wise" approach to addressing the retirement of generation at Hunters Point Power Plant, and working toward retiring Unit 4 as a "first step." (Exhibit 36.) Further, the CAISO has noted that in order to meet all grid planning and operational needs in the San Francisco Peninsula Area, approximately 400 MW of generation must be located north of San Mateo assuming the JM Project is in-service. (Exhibit 37 at 2, fn.2.) With the JM Project, Hunters Point Unit 4 may be retired and still satisfy the necessary 400 MW generation threshold. The same is not true, however, if the 50 MW of capacity from Hunters Point Unit 1 is also assumed retired. Without any generation from Hunters Point, generation capacity north of San Mateo

totals 391 MW (207 MW [Potrero Unit 3] + 156 MW [Potrero Units 4, 5 & 6] + 28 [United Airlines]). (See Exhibit 4 at 22:5-26:8; Exhibit 165 at 3:12-4:9.)

The fact that Hunters Point Unit 1 may continue to be needed to meet operational needs even after construction of the JM Project and after retirement of Hunters Point Unit 4 does not, however, affect the need for the JM Project by 2006 to ensure compliance with reliability criteria. 280 Corridor's own powerflow studies confirm this conclusion. In supplemental testimony, 280 Corridor presented the results of its powerflow study that utilized PG&E's low load forecast and varied PG&E's base case by assuming that Hunters Point Unit 1 was available to operate. Under this scenario, the "reported" result establishes that the highest loading on a 115 kV circuit within the Project Area is 99%. (Exhibit 154 at 3.) Loading which exceeds 100% of a facility rating constitutes an overload. However, even this reported result is inaccurate. The power-flow study provided by 280 Corridor revealed that the line loading, in fact, was 99.7%, or 100% if rounding under common convention. (Exhibit 156 at 3:11-19; Exhibit 165 at 4:18-5:17.) Accordingly, given the inherent uncertainty in any load forecast and especially considering the highly conservative assumptions embedded in PG&E's low load forecast, a 100% or fully loaded line represents an serious reliability concern that must be ameliorated prior to its occurrence under prudent planning principles. (Exhibit 165 at 4:27-5:4.) Accordingly, 280 Corridor's own data establishes Hunters Point Unit 1 remaining online does not obviate the need for the JM Project to address the capacity needs of the Project Area in the 2006.

IV. EVEN ASSUMING THE CCSF CTs ARE ASSUMED ONLINE, THE JM PROJECT IS STILL NEEDED BY AND A CPCN SHOULD BE ISSUED

Should the Commission elect to follow its precedent and prudent planning principles by excluding the CCSF CTs from the supply forecast, the outcome of this proceeding becomes clear – the CPCN must be immediately issued to permit construction of the JM Project by 2006 so that the load serving capability needs of the San Francisco Peninsula Area can be reliably met. However, even assuming the CCSF CTs are inappropriately included in the supply forecast for the San Francisco Peninsula Area, the need for the JM Project remains and the CPCN should be issued without delay.

The ORA recognizes that the JM Project remains "a longer term solution to the San Francisco Peninsula reliability problem." (Exhibit 46 at 8:21-22.) In this regard, ORA estimates, based on the CAISO's SF LSC Study, that the CCSF CTs would satisfy reliability needs only through approximately 2008 with the JM Project being needed thereafter. (*Id.* at 7:19-23 and 8:19-20.) As noted above, the CAISO's testimony updated the cases modeled in the final SF LSC Study by accounting for the impact of the Tesla-Newark 230 kV bundling project and the Newark-Ravenswood-Ames 115kV line project proposed in PG&E's 2003 Electric Transmission Grid Expansion Plan and approved by the CAISO. (Exhibit 165, Attachments 1 and 2.) The ORA's conclusions remain accurate when similarly updated and Hunters Point Power Plant is properly projected as retired. It should be emphasized that this latter condition inexorably corresponds with the assumption that the CCSF CTs are online. As the CAISO has expressly acknowledged, "all generation at Hunters Point can be retired if the following is successfully completed: 1) All transmission and generation requirements identified in the ISO's April 18, 2003

letter [Exhibit 36]; 2) The Tesla-Newark #2 –230kV line bundling is completed; and 3) the Ravenswood-Ames 115kV lines #1 and #2 are reconductored." (Exhibit 37.) Upon installation of the CCSF CTs, each of the enumerated preconditions will have been met, eliminating the underpinning for a continued Reliability Must Run contract and the final barrier to decommissioning the entire Hunters Point Power Plant pursuant to the terms of the 1998 agreement. (Exhibit 36 and Exhibit 37.)

Case 30 of the SF LSC Study can be evaluated to validate the ORA's analysis and determine the impact of modeling the Tesla-Newark 230kV and Ravenswood-Ames 115kV upgrades. Case 30 included the CCSF CTs and assumed Hunters Point Unit 4, but not Unit 1, was retired. Without the transmission upgrades, the driving point limitation was the Ravenswood-Ames 115kV line. (Exhibit 4, Attachment 6 at p. 108.) However, when the upgrades are considered, the relevant limitation becomes the Newark-Ravenswood 230kV circuit for an outage on the Tesla-Ravenswood 230kV circuit. The load serving capability of the San Francisco Peninsula under this scenario is 2086 MW. The effect of retiring Hunters Point Unit 1 must then be captured by subtracting approximately 52 MW. The resulting load serving capability is 2034 MW. PG&E's low load forecast for the San Francisco Peninsula for years 2009 is 2027. (Exhibit 163, Appendix 1.) While good sense dictates that the JM Project must be in place by 2009 to protect against the possibility of forecasting error (even under the unsupported assumption that all CCSF CTs' will be constructed),[14] it should be noted that

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[14] Tremendous uncertainty surrounds the siting and approval of the CCSF CTs. Given the vigorous level of opposition to generation resources traditionally expressed by local residents (Exhibit 46 at 3:17-23), a real possibility exists that the City will not choose or be able to seek approval for all of the CTs. If only three CCSF CTs are installed, for instance, the load serving capability for the San Francisco Peninsula falls to 1989 MW, which would require the JM Project be constructed to meet the 2007 low load forecast of 1978 MW. (Exhibit 163, Appendix 1.)

off-peak (winter) load levels on the San Francisco Peninsula are nearly identical to on-peak (summer) load levels and in some years exceed summer peak levels, suggesting completion of the project should be targeted for the end of year 2008.[15] (Exhibit 4 at 55:21-28.)

As the Commission noted in its *Valley-Rainbow* decision, its five-year planning horizon "should not be mechanistically applied but rather requires the exercise of judgment, based on the facts of each project."[16]An in-service date of 2008-2009 for the JM Project is approximately five years from PG&E's submission of load and supply forecast information and, therefore, conforms to the flexible five-year planning horizon adopted by the Commission in its *Valley-Rainbow* decision. More importantly, a rigid application of a bright-line planning horizon to the facts of this project would violate the Commission's rule of reason. First, dismissing the application in the present circumstances would constitute a waste of resources. To meet a reliability need arising at the beginning of 2009, PG&E would be required to immediately begin preparing to refile

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[15] It must be emphasized that there is no guarantee that actual peak load will not exceed forecasted load in any given year. Accordingly, unless reliability planning is based on a zero tolerance for error, the reliability solution must be in place prior to the year the load serving capability of the system approaches the load forecast. Moreover, as noted above, prudent reliability planning generally utilizes a median, rather than low, load forecast. Accordingly, relying solely on a low load forecast and deferring projects until the need becomes critical entails considerable risk to system performance given the long lead times for reliability solutions.

[16] *Valley-Rainbow* at p. 17. The CAISO disagrees with the fundamental premise of the Commission's adoption of a five-year planning horizon in *Valley-Rainbow.* The CAISO believes the *Valley-Rainbow* decision failed to properly account for the long lead time involved in permitting and building large high voltage transmission projects. The adoption of a five-year cut-off may either 1) discourage utilities from proposing long-lead time facilities since they are unlikely to be permitted in time to meet an identified need or 2) encourage utilities to wait until a need becomes critical.

its application for a CPCN given the very optimistic, minimum period of approximately 4 years to permit and construct the project.[17]

Second, the presence of any other solution (i.e. generation, transmission, or demand-side management) to address the San Francisco Peninsula Area's load serving capability needs into the future after the CCSF CTs is nonexistent or mere speculation. (Tr. 904:15-906:9, 907:5-11.) The JM Project constitutes the only tangible solution that is likely to be in place by the time it is needed. Under such circumstances, ORA's concern that the prompt issuance of a CPCN for the JM Project may result in ratepayers "overpaying" for reliability must be put into perspective. (Exhibit 46 at 8:9-16.) At most, the risk to ratepayers persists for only 2 to 3 years. More importantly, neither ORA nor any other intervenor provided any evidence that any purported cost savings from deferring construction of the JM Project would offset any potential increase in the cost of constructing the JM Project at a later date. (Tr. at 911:19-912:17, 936:6-10.) Indeed, the expert witness for the City of San Francisco testified:

> The installation of Jefferson-Martin would allow for more efficient dispatch of any remaining generation in the City, and support imports of lower cost electricity. It is my professional opinion that any potential costs of building Jefferson-Martin a few years before it is critically needed to meet current ISO Grid Planning Standards would be offset at least partially by the benefits of reduced costs of and reduction pollution from local generation. (Exhibit 84 at 6:6-10.)

Thus, regardless of whether the CCSF CTs are presumed online, there is no justification for the Commission to deny or delay ruling on the JM Project, and should the Commission do so, it would create unnecessary ambiguity as to how

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[17] See, *Proposed Interim Order on Transmission Needs in the Tehachapi Wind Resource Area,* I.00-11-001 (March 2, 2004), at p. 4, fn. 2 [minimum of one year to prepare a CPCN application].

the transmission system within the San Francisco Peninsula will meet mandatory reliability standards.

V. THE JM PROJECT PROVIDES MUCH NEEDED DIVERSIFICATION TO THE SAN FRANCISCO PENINSULA AREA TRANSMISSION SYSTEM

The CAISO stakeholder process selected the JM Project as the preferred option to ensure reliable electric service in the San Francisco Peninsula Area not only for its ability to increase the area's load serving capability, but also for its ability to diversify the path and source of imported power into the San Francisco Peninsula Area. (Exhibit 73 at 7, 71-77; Exhibit 38 at 10:3-8.) Currently, all major transmission lines travel through a single corridor from the San Mateo Substation to the Martin Substation and receive power solely from the San Mateo Substation. (Exhibit 4 at 5:24-25, 30:12-20.) As such, load in the San Francisco Peninsula Area is vulnerable to events disrupting supply from the San Mateo Substation and/or transported through the San Mateo-Martin corridor. (Exhibit 38 at 11:7-14.) The CAISO Long-Term Study emphasized that the JM Project would ameliorate this vulnerability in the transmission network by:

> Provid[ing] a different transmission source than [the] San Mateo Substation for serving the San Francisco area. The city would not be as exposed to interruptions associated with San Mateo Substation which is essentially the only source of externally generated power to the city. (Exhibit 73 at 7.)

CAISO witness Mr. DeShazo further clarified that the diversification provided by the JM Project encompasses the source of power as well as the transportation path for delivering power to the Project Area. "Whether the J-M line terminates at Martin or some location further within San Francisco, the ability to serve load in San Francisco and the peninsula will be 'diversified' by this project because it provides a second source of

power into a point in PG&E's system that benefits San Francisco and peninsula customers." (Exhibit 39 at 7:23-26.) Exhibit 167 visually depicts the added diversity created by the JM Project by providing a broad geographical view of the bulk transmission system associated with importing power into the San Francisco Peninsula Area. Exhibit 167 illustrates that without the JM Project, power imported into San Francisco Peninsula Area primarily originates from the East Bay via Tesla/Ravenswood 230kV line and Delta area generation and must pass through the San Mateo Substation. With the JM Project, the San Francisco Peninsula Area will benefit from an additional source of power from the south, via Moss Landing and Metcalf power plants through the Monta Vista-Jefferson 230kV lines.

The CAISO's powerflow results confirm that the diversity visually represented in Exhibit 167, in fact, corresponds to the physical reality of the electrical system. For the pre-JM Project case, load serving capability is constrained by a bottleneck on an import line across from the East Bay (Newark-Ravenswood 230 kV line). (Exhibit 165, Attachment 1.) In the post-JM case, the relevant constraint shifts from the East Bay to a limitation on the Shred Junction - Ravenswood 115kV line on the San Francisco Peninsula. (Exhibit 165, Attachment 2.) For the same East Bay constraint (Newark-Ravenswood 230 kV line), roughly 240 MW (2102-1862) more load for the San Francisco Peninsula Area can be served with the JM Project in service. This demonstrates that the effect of the JM Project is to replace power flows from the East Bay with power originating from the region south of the San Francisco Peninsula Area. (See also, Exhibit 38 at 11:3-6.)

The construction of an independent, second transmission path results in real and quantifiable benefits to consumers in the San Francisco Peninsula Area. As noted by PG&E, "the Jefferson-Martin Project would add about 400 MW more capability to serve load in the Project Area" in the event that the 115kV and/or 230kV system from the San Mateo Substation experienced a disruption. (Exhibit 15 at 13:19-14:6.) "This 400 MW of unaffected load serving capability would be able to supply about an additional 160,000 customers." (Exhibit 15 at 13:19-14:6.) Accordingly, the JM Project significantly reduces the risk of outage by diversifying the transmission system in the San Francisco Peninsula Area.

280 Corridor, however, asserts that the JM Project "or any new transmission path that terminates at the Martin Substation would not create a more diverse transmission system into San Francisco." (Exhibit 100 at 18.) Instead, 280 Corridor believes that the JM Project simply shifts the "choke point" on the existing transmission system north from the San Mateo Substation to the Martin Substation such that electrical service in San Francisco would be vulnerable to interruption if a problem occurred at the Martin Substation. (*Id.*) Implicit in 280 Corridor's position is that terminating the new 230kV line at the Martin Substation, rather than at some other substation, creates a reliability concern. 280 Corridor fails to offer any analytical support for its contentions. In fact, had it done so, 280 Corridor would have found its contentions without merit.

The CAISO Long-Term Study evaluated the relative benefits of terminating the new 230kV line at a substation other than Martin by performing various bus contingency studies. Such studies determined the amount of load

shedding necessary to prevent overloading transmission facilities under five bus outage scenarios.[18] Four project alternatives were reviewed with the results as follows:

Project Name	Aggregate Load Shedding Under All Contingencies (MWs)
Jefferson-Martin	1835
Jefferson-Hunters Pt	1900
San Mateo-Martin	1905
Moraga-Potrero	1955

The JM Project required the lowest amount of load shedding under all contingencies, even significantly lower than routing a 230kV line from Jefferson to Hunter's Point. (Exhibit 73 at 53.) Thus, greater reliability benefits result from terminating the new 230kV line from Jefferson Substation at the Martin Substation and 280 Corridor is simply wrong that the JM Project shifts the "choke point."

VI. THE COMMISSION MUST GIVE DUE DEFERENCE TO THE CAISO'S REVIEW AND APPROVAL OF THE PROJECT

The CAISO is aware that the Commission has confirmed in several decisions its belief that Public Utilities Code section 1001 "places an ongoing responsibility on this Commission to evaluate the public convenience and necessity of proposed transmission projects, and therefore [the Commission must] independently assess the record developed in this proceeding to determine whether the [JM Project] is needed" for reliability.[19] The

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[18] The five bus outages studies were: (1) loss of Hunter's Point 115kV bus; (2) loss of Martin 115kV bus; (3) loss of Potrero 115kV bus; (4) loss of San Mateo 230kV bus; and (5) loss of Martin 230kV bus. (Exhibit 73 at 53.)

[19] *Valley-Rainbow* at p. 7; see also, *In the matter of Application of Pacific Gas and Electric Company (U 39 E) for a Certificate of Public Convenience and Necessity Authorizing Construction of the Tri-Valley 2002 Capacity Increase Project,* D.01-10-029 (Oct. 11, 2001).

CAISO is further aware and commends the Commission for initiating Docket R.04-01-026, the purpose of which is to eliminate duplicative need determinations that currently exist at the CAISO and Commission.[20] Under the proposed rulemaking, General Order 131-D would be amended to allow the Commission to defer, in the context of an application for a CPCN, to the prior determination of project need reached by the CAISO in its Coordinated Grid Planning Process based upon Commission-adopted methodologies. The CAISO supports the Commission's proposal in R.04-01-026, but believes that regardless of the outcome of that docket, the law requires that the Commission afford due deference to the CAISO's determination of need in this proceeding. Thus, for the benefit of the record in this docket, the CAISO lays out in abbreviated form arguments it has raised in similar Commission CPCN proceedings.

Moreover, the corollary to the requirement that the Commission give due deference to the CAISO's need determinations regarding a particular transmission project is that the Commission must give less weight to transmission alternatives not supported by the CAISO.

A. The CPUC Should Give Due Deference to Determinations of Need by the CAISO as a Matter of Law

The CAISO has responsibility for transmission planning under both California and federal law. Under California law, the Commission retains responsibility for siting. California rules of statutory interpretation provide that specific statutory provisions must be read in the context of the full statutory framework, in a manner that is workable and reasonable, and that avoids absurd results. If the rules of statutory construction are applied to the relevant statutory provisions, the only fair conclusion that

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[20] *Order Instituting Rulemaking on Policies and Practices for the Commission's Transmission Assessment Process,* R.04-01-026 (Jan. 22, 2004), at pp. 1, 5.

can be drawn is that the Commission should give due consideration to CAISO determinations that new transmission facilities are needed.

AB 1890 transferred responsibility for ensuring grid reliability from the State's investor owned utilities and the Commission to the CAISO. Public Utilities Code section 345 states "[t]he Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council." Further, Public Utilities Code section 334 provides explicitly that "[t]he proposed restructuring of the electric industry would transfer responsibility for ensuring short- and long- term reliability away from electric utilities and regulatory bodies to the Independent System Operator . . . " (emphasis added) and creates the Electricity Oversight Board to ensure that state interests are protected notwithstanding the transfer.

Transmission planning is an integral part of assuring transmission grid reliability. Without adequate facilities it is not possible to "ensure efficient use and reliable operation of the transmission grid." Moreover, Public Utilities Code section 345 explicitly notes that the CAISO must ensure compliance with planning criteria as well as operating reserve criteria, making it clear that the CAISO has responsibility to provide for transmission planning.

In addition, AB 1890 required the CAISO to make appropriate filings with the Federal Energy Regulatory Commission ("FERC") to "request confirmation of the relevant provisions of this chapter and seek the authority needed to give the Independent System Operator the ability to secure generating and transmission resources necessary to

guarantee achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council."[21] Consistent with this directive, the CAISO filed a comprehensive tariff at FERC that provided for the creation of a transmission planning function led and coordinated by the CAISO. This section is necessary to give the CAISO the ability to secure "the transmission resources necessary to guarantee achievement of planning ... criteria", in accordance with Public Utilities Code section 346.

Further, it was a clear objective of the California legislature in passing AB 1890 that the CAISO be accepted as an Independent System Operator by the FERC: consistent with FERC nomenclature, AB 1890 named the institution created to operate the transmission system Independent System Operator (see e.g. Public Utilities Code § 345); the legislation endorsed the characteristics of Independent System Operators that had been articulated by FERC (see e.g. Public Utilities Code § 330(k)); and the legislation required the CAISO to obtain appropriate authorization to provide for a competitive electricity market from FERC (Public Utilities Code § 346). CAISO coordination of transmission planning was a prerequisite of FERC's recognition of the CAISO as an Independent System Operator (see, 77 FERC ¶61,204, pp. 61,834-36 (November 26, 1996); 80 FERC ¶ 61,128, pp. 61,416-35 (July 30, 1997)). These factors are further evidence of the clear intent on the part of the California legislature to transfer responsibility for transmission planning to the CAISO.

Finally, given the FERC directive mentioned above, that the CAISO must coordinate transmission planning, and subsequent FERC determinations approving the transmission planning section of the CAISO's tariff (see e.g. 81 FERC ¶ 61,122, 61,459

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[21] Public Utilities Code § 346.

(October 30, 1997); 80 FERC ¶ 61,128, 61,430-35 (July 30, 1997)), the CAISO has planning responsibilities under federal as well as state law. Since state and federal law are in accord as to CAISO responsibility for transmission planning, it is unnecessary to discuss federal preemption issues.[22]

The CAISO recognizes, however, that AB 1890 did not revise state law as to transmission facility siting as set forth in Public Utilities Code section 1001, et seq. Public Utilities Code section 1001 provides that no electrical corporation shall begin construction of a line "without having first obtained from the [California Public Utilities Commission] a certificate that the present or future public convenience and necessity require or will require such construction." Thus, in Commission CPCN proceedings, utilities must still show need, as well as address other factors that must be considered by the Commission under CEQA and Public Utilities Code section 1002.

The CAISO's responsibilities in the wake of AB 1890 and the Commission's continued responsibilities in the context of transmission siting under Public Utilities Code section 1001, et seq, are easily harmonized as required under California rules of statutory construction.[23] To give effect to the CAISO's transmission planning responsibilities, the method by which utilities are to demonstrate need in the context of CPCN proceedings should now be to demonstrate, with the assistance of the CAISO, that need has been found by the CAISO in the context of the CAISO's coordinated planning process. Any other interpretation renders the transmission planning work undertaken by the CAISO in

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[22] If state and federal law were in conflict as to CAISO responsibility for transmission planning, which they are not, federal preemption issues requiring further analysis would arise.

[23] *Maricela C. v. Superior Court* (1998) 66 Cal.App.4th 1138; 1143-4 ["The parts of a statute must be harmonized by considering the particular clause or section in the context of the statutory framework as a whole."].

accordance with its responsibilities under AB 1890 and federal law superfluous and ineffective, contrary to California rules of statutory interpretation.

In sum, in accordance with state and federal law, the Commission should give due consideration in this proceeding to the determination by the CAISO that the JM Project is necessary.

B. 280 Corridor's Solution to Rerate the San Mateo-Martin 115kV Circuits Fails to Relieve Reliability Concerns and Must Be Disregarded

An obligation to give due deference to the CAISO's determination of project need also unavoidably encompasses deferring to CAISO evaluations that conclude a particular transmission project is inferior to the selected project and unnecessary to meet reliability needs. In this regard, the Commission should disregard 280 Corridor's claim that the need for additional load serving capability in the Project Area can be solved by rerating the overhead San Mateo-Martin 115kV circuits to 261 MW using a four foot-per-second wind speed (Exhibit 100 at 24-25) and an assumption that the underground "dips" in the San-Mateo-Martin 115kV corridor can accommodate 261 MVA during peak load periods. (Exhibit 100 at 24-25; Exhibit 101 at 3-4; Exhibit 154.)

280 Corridor's solution is fatally flawed. First, 280 Corridor's proposed solution was advanced without performing a power-flow analysis. When 280 Corridor belatedly attempted to correct this admittedly fundamental error,[24] its own power-flow results demonstrated that the proposed solution fails to relieve facility overloading in year-2006 under PG&E's low load forecast. (Exhibit 154 at p. 2, Table 2, Case 4.) The proposed

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[24] 280 Corridor witness Mr. Shields was asked whether he "under[stood] that it is not an accurate method of determining load-serving capability to simply add up the capabilities of generation units and transmission lines without conducting a power-flow analysis." Mr. Shields responded: "I do understand that there has to be a power-flow analysis to provide the basis for those numbers. So I understand that, yes. There is a requirement for a power-flow study." (Tr. at 1903:13-21.)

re-rate solution similarly fails to ensure reliable system performance even when augmented by an assumption that Hunter's Point Unit 1 remains online. Under this scenario, the reported result, similar to the outcome reviewing Hunters Point Unit 1 alone, establishes that the highest loading on a 115 kV circuit within the corridor is 99%. (*Id.,* Case 5.) Again, even this "reported" result is inaccurate and is, in fact, 100%. (Exhibit 165 at 4:19-5:16; Exhibit 156 at 3:3-4:28.) Accordingly, 280 Corridor's own data establishes that its proposed rerate solution, either alone or in conjunction with the assumption that Hunters Point Unit 1 will remain online, fails to address the capacity needs of the Project Area.

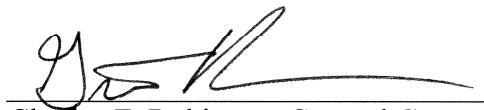
Second, the readjusted line ratings fail to address import line constraints that must be addressed to meet projected load serving capability needs within the Project Area. The power flow analysis submitted by 280 Corridor does not address the emergency overload problems that might occur during summer peak conditions. Case 29 within the CAISO SF LSC Study clearly shows that during summer peak conditions, even with the Hunters Point Unit 1 online, the resultant load serving capability will be insufficient to meet the projected 2006 load. Power imported into the San Francisco Peninsula Area would be limited by the re-rated capacity of the Newark-Ravenswood 230 kV line, which cannot be mitigated by the proposed reratings. Not enough power can be imported across San Francisco Bay (through the Newark-Ravenswood 230 kV line with the Tesla-Ravenswood 230 kV line out) to serve all San Francisco and Peninsula load in 2006 without Hunters Point Unit 4. The Jefferson-Martin 230 kV line would function as a parallel circuit with the existing 230 kV lines into Ravenswood and San Mateo Substations, and therefore will increase the amount of power that can be imported into

San Francisco and the Peninsula while avoiding the potential overloading of the Newark-Ravenswood 230 kV line. Without the proposed project and without Hunters Point Units 1 & 4, the San Francisco Peninsula load serving capability is 1862 MW with the limitation located at the Newark-Ravenswood 230 kV line. In contrast, with the proposed project the San Francisco Peninsula load serving capability increases to 2092 MW. This demonstrates that the JM Project relieves limitations across import lines from the East Bay. Therefore, the proposed project is needed not just for relieving limitations within the San Mateo corridor, but also for relieving import line constraints that cannot be fixed by 280 Corridor's proposed higher adjusted ratings for the San-Mateo-Martin transmission system. (Exhibit 165 at 6:21-7:14, Attachments 1 and 2.)

VII. CONCLUSION

The need for the JM Project to ensure reliability by 2006 has been amply demonstrated. Consequently, the CAISO respectfully urges the Commission to expeditiously issue a CPCN for the JM Project.

Respectfully submitted,



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Dated: March 4, 2004

APPENDIX 1

BUREAU OF ECONOMIC ANALYSIS

BEA NEWS

WWW.BEA.GOV

EMBARGOED UNTIL RELEASE AT 8:30 A.M. EST, FRIDAY, FEBRUARY 27, 2004

Virginia H. Mannering: (202) 606-5304 (GDP)
Recorded message: (202) 606-5306

BEA 04-08

GROSS DOMESTIC PRODUCT: FOURTH QUARTER 2003 (PRELIMINARY)

Real gross domestic product -- the output of goods and services produced by labor and property located in the United States -- increased at an annual rate of 4.1 percent in the fourth quarter of 2003, according to preliminary estimates released by the Bureau of Economic Analysis. In the third quarter, real GDP increased 8.2 percent.

The GDP estimates released today are based on more complete source data than were available for the advance estimates issued last month. In the advance estimates, the increase in real GDP was 4.0 percent (see "Revisions" on page 3).

The major contributors to the increase in real GDP in the fourth quarter were personal consumption expenditures (PCE), exports, equipment and software, private inventory investment, and residential fixed investment. Imports, which are a subtraction in the calculation of GDP, increased.

The deceleration in real GDP growth in the fourth quarter primarily reflected a deceleration in PCE, an acceleration in imports, and a deceleration in residential fixed investment that were partly offset by an upturn in private inventory investment and an acceleration in exports.

Final sales of computers contributed 0.28 percentage point to the fourth-quarter change in real GDP after contributing 0.65 percentage point to the third-quarter change. Motor vehicle output contributed 0.10 percentage point to the fourth-quarter change in real GDP after contributing 0.82 percentage point to the third-quarter change.

The price index for gross domestic purchases, which measures prices paid by U.S. residents, increased 1.1 percent in the fourth quarter, 0.1 percentage point more than the advance estimate; this index increased 1.8 percent in the third quarter. Excluding food and energy prices, the price index for gross domestic purchases increased 1.2 percent in the fourth quarter, compared with an increase of 1.3 percent in the third.

NOTE.--Quarterly estimates are expressed at seasonally adjusted annual rates, unless otherwise specified. Quarter-to-quarter dollar changes are differences between these published estimates. Percent changes are calculated from unrounded data and annualized. "Real" estimates are in chained (2000) dollars. Price indexes are chain-type measures.

This news release is available on BEA's Web site at <www.bea.gov/bea/rels.htm>.

- more -

Real personal consumption expenditures increased 2.7 percent in the fourth quarter, compared with an increase of 6.9 percent in the third. Real nonresidential fixed investment increased 9.6 percent, compared with an increase of 12.8 percent. Nonresidential structures decreased 7.1 percent, compared with a decrease of 1.8 percent. Equipment and software increased 15.1 percent, compared with an increase of 17.6 percent. Real residential fixed investment increased 8.6 percent, compared with an increase of 21.9 percent.

Real exports of goods and services increased 21.0 percent in the fourth quarter, compared with an increase of 9.9 percent in the third. Real imports of goods and services increased 16.4 percent, compared with an increase of 0.8 percent.

Real federal government consumption expenditures and gross investment increased 1.6 percent in the fourth quarter, compared with an increase of 1.2 percent in the third. National defense increased 4.2 percent, in contrast to a decrease of 1.3 percent. Nondefense decreased 3.3 percent, in contrast to an increase of 6.5 percent. Real state and local government consumption expenditures and gross investment increased 0.4 percent, compared with an increase of 2.1 percent.

The real change in private inventories added 0.92 percentage point to the fourth-quarter change in real GDP, after subtracting 0.13 percentage point from the third-quarter change. Private businesses increased inventories $14.9 billion in the fourth quarter, following decreases of $9.1 billion in the third quarter and $4.5 billion in the second.

Real final sales of domestic product -- GDP less change in private inventories -- increased 3.2 percent in the fourth quarter, compared with an increase of 8.3 percent in the third.

Gross domestic purchases

Real gross domestic purchases -- purchases by U.S. residents of goods and services wherever produced -- increased 4.2 percent in the fourth quarter, compared with an increase of 7.0 percent in the third.

Current-dollar GDP

Current-dollar GDP -- the market value of the nation's output of goods and services -- increased 5.3 percent, or $145.3 billion, in the fourth quarter to a level of $11,252.3 billion. In the third quarter, current-dollar GDP increased 10.0 percent, or $260.3 billion.

Revisions

The preliminary estimate of the fourth-quarter increase in real GDP is 0.1 percentage point, or $2.1 billion, higher than the advance estimate issued last month. The upward revision to the percentage change in real GDP primarily reflected upward revisions to equipment and software, to private inventory investment, to exports, and to personal consumption expenditures for nondurable goods that were mostly offset by an upward revision to imports.

	Advance	Preliminary
	(Percent change from preceding quarter)	
Real GDP	4.0	4.1
Current-dollar GDP	5.1	5.3
Gross domestic purchases price index	1.0	1.1

2003 GDP

Real GDP increased 3.1 percent in 2003 (that is, from the 2002 annual level to the 2003 annual level), compared with an increase of 2.2 percent in 2002.

The major contributors to the increase in real GDP in 2003 were personal consumption expenditures (PCE), federal government spending, equipment and software, and residential fixed investment. Imports, which are a subtraction in the calculation of GDP, increased in 2003.

The acceleration in real GDP in 2003 primarily reflected an upturn in equipment and software, a smaller decrease in nonresidential structures, and an upturn in exports that were partly offset by a downturn in private inventory investment.

The price index for gross domestic purchases increased 1.9 percent in 2003, compared with an increase of 1.4 percent in 2002.

Current-dollar GDP increased 4.8 percent, or $504.7 billion, in 2003. Current-dollar GDP increased 3.8 percent, or $380.0 billion, in 2002.

During 2003 (that is, measured from the fourth quarter of 2002 to the fourth quarter of 2003), real GDP increased 4.3 percent. Real GDP increased 2.8 percent during 2002. The price index for gross domestic purchases increased 1.6 percent during 2003, compared with an increase of 1.7 percent during 2002.

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* * *

Next release -- March 25, 2004, at 8:30 A.M. EST for:
Gross Domestic Product: Fourth Quarter 2003 (Final)
Corporate Profits: Fourth Quarter 2003

Table 1.—Real Gross Domestic Product and Related Measures: Percent Change From Preceding Period

	2001	2002	2003 r	Seasonally adjusted at annual rates															
				2000				2001				2002				2003			
				I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV r
Gross domestic product (GDP)	**0.5**	**2.2**	**3.1**	**1.0**	**6.4**	**–0.5**	**2.1**	**–0.2**	**–0.6**	**–1.3**	**2.0**	**4.7**	**1.9**	**3.4**	**1.3**	**2.0**	**3.1**	**8.2**	**4.1**
Personal consumption expenditures	**2.5**	**3.4**	**3.1**	**6.5**	**2.5**	**3.9**	**3.4**	**.5**	**2.3**	**1.9**	**6.2**	**4.1**	**2.6**	**2.0**	**2.2**	**2.5**	**3.3**	**6.9**	**2.7**
Durable goods	4.1	6.5	7.3	24.4	–9.5	6.0	.7	1.7	9.8	.7	27.3	1.6	.5	5.0	.3	.5	17.7	28.0	–.1
Nondurable goods	1.9	3.0	3.8	.3	5.7	2.3	3.7	.4	–1.1	2.9	4.7	6.1	.4	.2	4.6	5.7	1.2	7.3	5.2
Services	2.4	3.0	2.0	6.0	3.9	4.3	3.9	.3	2.4	1.6	2.8	3.8	4.1	2.2	1.5	1.5	1.7	2.8	2.2
Gross private domestic investment	**–8.4**	**–1.2**	**4.3**	**–6.9**	**29.1**	**–9.9**	**–2.3**	**–11.1**	**–16.4**	**–8.5**	**–17.7**	**11.1**	**4.6**	**11.4**	**–.6**	**–3.5**	**4.7**	**14.8**	**15.8**
Fixed investment	–3.2	–3.7	4.4	11.5	9.5	–.6	.7	–2.7	–9.2	–5.2	–10.8	–2.5	.6	.6	2.1	1.1	6.1	15.8	9.3
Nonresidential	–4.5	–7.2	2.9	14.3	14.8	2.2	.9	–4.5	–13.6	–8.4	–14.0	–7.0	–3.0	–1.1	–.1	–.6	7.0	12.8	9.6
Structures	–2.5	–18.4	–5.0	7.0	18.0	9.6	1.2	–5.9	–5.6	2.2	–35.3	–23.9	–14.5	–14.6	–5.6	–4.0	3.9	–1.8	–7.1
Equipment and software	–5.2	–2.8	5.5	16.9	13.7	–.2	.8	–4.0	–16.4	–12.2	–4.1	–.2	1.2	3.7	1.7	.5	8.0	17.6	15.1
Residential	.4	4.9	7.5	4.1	–3.5	–8.0	.4	2.6	3.7	3.1	–2.5	8.7	8.9	4.2	6.8	4.5	4.5	21.9	8.6
Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Net exports of goods and services	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Exports	–5.2	–2.4	2.1	6.6	12.3	10.7	–2.7	–4.5	–13.4	–17.7	–9.8	4.4	8.7	4.3	–3.7	–2.0	–1.1	9.9	21.0
Goods	–6.1	–4.0	1.9	8.7	13.8	18.3	–5.4	–5.4	–18.1	–18.9	–7.6	–2.6	12.0	4.3	–9.1	1.9	–1.7	8.6	21.2
Services	–3.1	1.4	2.4	1.4	8.5	–6.6	4.4	–2.0	–.6	–14.7	–15.0	22.8	1.6	4.5	9.4	–10.1	.2	12.7	20.7
Imports	–2.6	3.3	4.0	16.7	16.5	14.1	–1.6	–6.2	–8.6	–10.8	–3.8	8.4	17.1	4.1	8.2	–6.8	9.1	.8	16.4
Goods	–3.2	3.7	4.8	16.0	17.7	14.1	–1.6	–6.8	–12.2	–9.2	–3.2	6.3	21.9	4.8	7.4	–6.6	13.7	–1.5	18.1
Services	.4	1.4	0	20.8	10.7	14.1	–1.9	–3.1	12.5	–18.2	–6.9	19.2	–3.6	.7	12.2	–7.5	–10.9	13.4	8.6
Government consumption expenditures and gross investment	**2.8**	**3.8**	**3.4**	**–3.0**	**5.5**	**–2.1**	**1.3**	**5.8**	**5.8**	**–4.1**	**7.4**	**4.6**	**4.0**	**2.5**	**7.1**	**–.4**	**7.4**	**1.8**	**.8**
Federal	3.7	7.9	8.8	–13.9	17.2	–8.2	–1.0	8.9	6.7	0	9.9	8.4	10.5	3.9	18.2	–.2	23.5	1.2	1.6
National defense	3.9	8.9	10.6	–21.3	17.0	–7.4	1.7	7.7	2.6	2.4	14.2	8.2	9.5	4.5	22.1	–5.6	41.9	–1.3	4.2
Nondefense	3.5	6.2	5.3	1.2	17.6	–9.7	–5.7	11.2	14.4	–4.3	2.6	8.7	12.2	2.9	11.4	10.5	–5.0	6.5	–3.3
State and local	2.2	1.8	.5	3.2	.1	1.3	2.5	4.3	5.3	–6.1	6.1	2.7	.7	1.7	1.5	–.5	–.8	2.1	.4
Addenda:																			
Final sales of domestic product	1.4	1.8	3.1	4.2	3.3	1.3	2.6	1.4	.7	–.7	3.2	2.6	1.3	1.8	1.7	2.7	3.3	8.3	3.2
Gross domestic purchases	.7	2.8	3.3	2.5	7.2	.4	2.1	–.7	–.4	–.8	2.4	5.2	3.1	3.4	2.7	1.1	4.3	7.0	4.2
Final sales to domestic purchasers	1.6	2.4	3.4	5.6	4.2	2.1	2.6	.9	.9	–.3	3.6	3.2	2.5	1.8	3.1	1.8	4.5	7.2	3.3
Gross national product (GNP)	.5	2.1	.....	.8	6.6	–.7	3.0	–1.3	–.6	–1.9	4.6	2.6	1.3	3.8	2.0	1.5	3.3	8.3	.....
Disposable personal income	1.8	3.8	2.5	9.2	2.7	5.2	.6	–.3	–1.4	12.2	–4.4	10.6	4.1	–.9	.6	2.4	4.9	6.3	0
Current-dollar measures:																			
GDP	2.9	3.8	4.8	4.7	8.3	1.6	3.8	2.9	2.6	.3	3.9	5.4	3.9	4.4	3.1	4.3	4.2	10.0	5.3
Final sales of domestic product	3.9	3.3	4.9	7.8	5.4	3.2	4.5	4.5	4.0	.9	4.8	3.8	2.8	3.3	3.5	5.1	4.4	10.1	4.4
Gross domestic purchases	2.7	4.2	5.3	6.6	8.9	2.9	3.7	1.9	1.9	.2	3.3	5.8	6.1	4.6	4.5	4.5	4.7	8.9	5.3
Final sales to domestic purchasers	3.6	3.8	5.3	9.7	6.1	4.5	4.4	3.5	3.3	.7	4.1	4.2	5.0	3.5	4.8	5.3	4.8	9.1	4.4
GNP	2.8	3.6	.....	4.4	8.4	1.4	4.7	1.8	2.5	–.3	6.5	3.3	3.3	4.9	3.9	3.9	4.4	10.1	.....
Disposable personal income	3.8	5.2	4.4	13.0	4.7	7.2	2.4	2.9	1.1	12.8	–4.1	11.4	7.2	1.1	2.3	5.3	5.4	8.1	.6

r Revised.
See "Explanatory Note" at the end of the tables.

Table 2.—Contributions to Percent Change in Real Gross Domestic Product

	2001	2002	2003 r	Seasonally adjusted at annual rates															
				2000				2001				2002				2003			
				I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV r
Percent change at annual rate:																			
Gross domestic product	**0.5**	**2.2**	**3.1**	**1.0**	**6.4**	**–0.5**	**2.1**	**–0.2**	**–0.6**	**–1.3**	**2.0**	**4.7**	**1.9**	**3.4**	**1.3**	**2.0**	**3.1**	**8.2**	**4.1**
Percentage points at annual rates:																			
Personal consumption expenditures	**1.68**	**2.38**	**2.20**	**4.38**	**1.78**	**2.62**	**2.29**	**.28**	**1.52**	**1.27**	**4.20**	**2.92**	**1.81**	**1.39**	**1.57**	**1.80**	**2.34**	**4.89**	**1.93**
Durable goods	**.36**	**.55**	**.61**	**1.96**	**–.89**	**.50**	**.06**	**.15**	**.80**	**.06**	**2.14**	**.14**	**.04**	**.43**	**.02**	**.04**	**1.38**	**2.23**	**–.01**
Motor vehicles and parts	.19	.18	.17	1.31	–1.12	.28	.01	.04	.67	–.13	1.58	–.44	–.25	.29	–.33	–.16	.54	1.36	–.40
Furniture and household equipment	.18	.30	.28	.45	.19	.19	.07	.18	.16	.23	.40	.45	.23	.12	.24	.04	.54	.65	.29
Other	–.01	.08	.16	.19	.04	.03	–.02	–.07	–.02	–.04	.16	.13	.05	.02	.11	.17	.30	.21	.10
Nondurable goods	**.37**	**.60**	**.76**	**.06**	**1.11**	**.44**	**.72**	**.06**	**–.22**	**.57**	**.91**	**1.19**	**.07**	**.04**	**.90**	**1.13**	**.25**	**1.48**	**1.04**
Food	.12	.22	.37	.16	.39	.09	.14	.22	–.03	.02	.14	.56	.19	.03	.22	.63	.23	.71	.37
Clothing and shoes	.06	.15	.13	.27	.21	.19	.04	–.08	.01	.15	.19	.33	.01	–.01	.21	.09	.21	.27	.02
Gasoline, fuel oil, and other energy goods	.03	.04	–.01	–.13	–.06	–.05	.25	.12	–.37	.09	.32	.10	–.20	–.09	.21	.08	–.40	.07	.31
Other	.15	.20	.26	–.23	.56	.21	.29	–.19	.17	.31	.27	.22	.07	.11	.25	.33	.20	.43	.33
Services	**.96**	**1.23**	**.84**	**2.36**	**1.55**	**1.67**	**1.51**	**.07**	**.94**	**.64**	**1.15**	**1.58**	**1.70**	**.92**	**.65**	**.63**	**.71**	**1.19**	**.91**
Housing	.28	.29	.24	.32	.31	.27	.28	.33	.26	.21	.25	.35	.33	.28	.25	.26	.20	.25	.18
Household operation	0	.04	.02	.12	.51	.16	.41	–.27	–.31	–.05	–.17	.18	.36	–.14	.04	.04	–.13	.14	.02
Electricity and gas	–.02	.04	0	–.05	.33	.07	.40	–.15	–.49	–.04	–.13	.20	.27	–.05	.09	.01	–.21	.06	–.02
Other household operation	.02	0	.02	.18	.18	.08	.01	–.12	.17	–.01	–.04	–.02	.09	–.09	–.05	.03	.08	.08	.04
Transportation	–.02	–.05	–.06	.12	.08	–.01	.01	.03	–.01	–.15	–.14	.10	–.05	–.12	–.09	.01	–.11	–.06	–.06
Medical care	.45	.63	.59	.37	.47	.41	.42	.35	.47	.62	.61	.75	.61	.51	.69	.59	.53	.60	.59
Recreation	.06	.11	.06	.06	.14	.10	.04	.09	–.02	.06	.15	.19	.07	.05	.09	0	.10	.08	.12
Other	.18	.20	–.01	1.37	.05	.75	.34	–.45	.56	–.06	.45	0	.38	.34	–.33	–.28	.13	.19	.08
Gross private domestic investment	**–1.47**	**–.18**	**.64**	**–1.30**	**4.65**	**–1.84**	**–.36**	**–1.96**	**–2.92**	**–1.39**	**–2.98**	**1.60**	**.69**	**1.66**	**–.09**	**–.57**	**.73**	**2.17**	**2.31**
Fixed investment	**–.54**	**–.60**	**.66**	**1.83**	**1.60**	**–.10**	**.13**	**–.45**	**–1.60**	**–.88**	**–1.83**	**–.41**	**.08**	**.08**	**.31**	**.16**	**.90**	**2.30**	**1.39**
Nonresidential	–.56	–.82	.29	1.64	1.76	.28	.11	–.56	–1.76	–1.02	–1.71	–.81	–.33	–.12	–.01	–.06	.68	1.25	.95
Structures	–.08	–.59	–.13	.21	.53	.29	.04	–.20	–.19	.07	–1.36	–.77	–.41	–.40	–.14	–.10	.09	–.04	–.17
Equipment and software	–.47	–.23	.42	1.44	1.23	–.02	.07	–.37	–1.57	–1.09	–.35	–.03	.09	.28	.13	.04	.59	1.30	1.12
Information processing equipment and software	–.10	.02	.54	1.13	.96	.33	.58	–.20	–.84	–.58	–.15	.09	.37	.53	–.06	.64	.64	1.05	.69
Computers and peripheral equipment	.02	.11	.24	.22	.45	.12	.06	.16	–.22	–.26	.19	.22	.06	.28	.09	.21	.33	.39	.25
Software	–.04	–.04	.14	.17	.18	.02	.20	–.07	–.24	–.16	–.21	–.05	.09	.21	–.06	.18	.15	.24	.25
Other	–.08	–.05	.16	.74	.33	.19	.32	–.28	–.39	–.16	–.14	–.08	.21	.05	–.10	.26	.15	.41	.19
Industrial equipment	–.14	–.09	–.05	.29	.14	.09	–.12	.04	–.53	–.30	–.22	.26	–.21	0	–.04	–.10	–.02	.02	–.01
Transportation equipment	–.18	–.14	–.11	–.12	.04	–.31	–.36	–.27	0	–.25	.24	–.34	–.24	–.26	.20	–.37	–.09	–.05	.24
Other equipment	–.05	–.02	.04	.13	.09	–.13	–.03	.06	–.21	.04	–.21	–.04	.17	0	.04	–.13	.05	.28	.20
Residential	.02	.23	.36	.19	–.16	–.38	.02	.12	.16	.14	–.12	.40	.41	.20	.32	.22	.22	1.05	.44
Change in private inventories	**–.93**	**.41**	**–.01**	**–3.13**	**3.05**	**–1.74**	**–.49**	**–1.51**	**–1.32**	**–.51**	**–1.15**	**2.01**	**.61**	**1.58**	**–.40**	**–.74**	**–.17**	**–.13**	**.92**
Farm	.02	–.03	.02	–.51	.88	–.36	.34	.03	–.34	.14	–.26	.39	–.64	.34	–.02	.15	–.09	–.03	.10
Nonfarm	–.94	.44	–.04	–2.62	2.18	–1.38	–.83	–1.54	–.99	–.65	–.89	1.62	1.25	1.25	–.38	–.88	–.08	–.10	.82
Net exports of goods and services	**–.19**	**–.70**	**–.35**	**–1.53**	**–.98**	**–.87**	**–.07**	**.46**	**–.25**	**–.42**	**–.50**	**–.65**	**–1.32**	**–.15**	**–1.47**	**.81**	**–1.34**	**.80**	**–.30**
Exports	**–.58**	**–.24**	**.20**	**.70**	**1.30**	**1.14**	**–.31**	**–.50**	**–1.54**	**–1.99**	**–1.02**	**.40**	**.80**	**.41**	**–.37**	**–.19**	**–.11**	**.92**	**1.85**
Goods	–.48	–.29	.13	.65	1.03	1.36	–.45	–.44	–1.52	–1.50	–.54	–.19	.75	.28	–.64	.13	–.11	.56	1.28
Services	–.10	.04	.07	.05	.26	–.22	.14	–.06	–.02	–.48	–.47	.59	.05	.13	.27	–.31	.01	.36	.57
Imports	**.39**	**–.45**	**–.55**	**–2.23**	**–2.27**	**–2.01**	**.24**	**.96**	**1.29**	**1.57**	**.52**	**–1.05**	**–2.12**	**–.56**	**–1.10**	**1.00**	**–1.24**	**–.12**	**–2.15**
Goods	.39	–.42	–.55	–1.79	–2.03	–1.70	.19	.88	1.57	1.10	.35	–.66	–2.20	–.55	–.83	.81	–1.51	.18	–1.95
Services	–.01	–.03	0	–.44	–.24	–.32	.04	.08	–.28	.47	.16	–.39	.09	–.02	–.27	.19	.27	–.30	–.20
Government consumption expenditures and gross investment	**.48**	**.69**	**.63**	**–.56**	**.96**	**–.37**	**.22**	**.99**	**1.00**	**–.74**	**1.28**	**.85**	**.72**	**.46**	**1.29**	**–.07**	**1.36**	**.34**	**.16**
Federal	**.22**	**.48**	**.56**	**–.93**	**.96**	**–.51**	**–.07**	**.50**	**.38**	**0**	**.57**	**.52**	**.64**	**.26**	**1.11**	**–.01**	**1.46**	**.09**	**.11**
National defense	.15	.35	.44	–.92	.61	–.29	.06	.27	.10	.09	.53	.33	.38	.19	.85	–.25	1.58	–.06	.19
Consumption expenditures	.13	.29	.40	–.88	.60	–.30	.11	.29	0	.03	.50	.32	.22	.09	.93	–.19	1.39	–.20	.17
Gross investment	.02	.06	.05	–.04	.01	.01	–.05	–.01	.10	.06	.02	.01	.15	.10	–.07	–.06	.19	.13	.02
Nondefense	.07	.14	.12	–.01	.35	–.22	–.13	.23	.28	–.09	.04	.20	.27	.07	.26	.24	–.12	.15	–.08
Consumption expenditures	.07	.12	.11	.21	.28	–.13	–.06	.19	.19	–.02	.06	.14	.15	.13	.26	.25	–.26	.23	–.16
Gross investment	0	.02	.02	–.22	.07	–.09	–.07	.04	.09	–.07	–.02	.06	.11	–.06	0	–.01	.14	–.08	.08
State and local	**.26**	**.21**	**.06**	**.36**	**.01**	**.15**	**.29**	**.49**	**.62**	**–.74**	**.71**	**.33**	**.08**	**.20**	**.18**	**–.06**	**–.10**	**.25**	**.05**
Consumption expenditures	.20	.13	.06	.09	.16	.10	.21	.29	.22	.13	.21	.01	.17	.11	.19	.06	–.05	–.02	.03
Gross investment	.06	.08	0	.28	–.15	.05	.08	.20	.40	–.88	.50	.31	–.09	.09	–.01	–.12	–.05	.27	.02
Addenda:																			
Goods	–.71	.71	1.42	–.92	3.64	–1.19	.10	–1.17	–2.08	–1.40	1.38	2.54	–.37	2.12	–.92	1.37	.75	5.67	2.54
Services	1.26	1.77	1.48	1.40	2.63	.80	1.95	.85	1.05	.77	1.61	2.25	2.38	1.37	2.02	.62	2.08	1.27	1.32
Structures	–.04	–.29	.23	.51	.15	–.07	.03	.09	.38	–.65	–1.00	–.08	–.10	–.13	.19	–.02	.26	1.27	.25
Motor vehicle output	–.17	.38	.09	.21	–.62	–.73	–.47	–.53	.58	.05	.92	.39	.20	.37	–.18	–.23	.07	.82	.10
Final sales of computers	.14	.10	.31	.52	.47	.10	.19	.45	–.20	–.19	.22	.06	.06	.35	.26	.26	.25	.65	.28

r Revised.
See "Explanatory Note" at the end of the tables.

Table 3.—Gross Domestic Product and Related Measures: Level and Change From Preceding Period

	Billions of current dollars						Billions of chained (2000) dollars								
		Seasonally adjusted at annual rates						Seasonally adjusted at annual rates					Change from preceding period		
	2003 r	2002	2003				2003 r	2002	2003				2003 r	2003	
		IV	I	II	III	IV r		IV	I	II	III	IV r		III	IV r
Gross domestic product	**10,985.5**	**10,623.7**	**10,735.8**	**10,846.7**	**11,107.0**	**11,252.3**	**10,397.7**	**10,160.8**	**10,210.4**	**10,288.3**	**10,493.1**	**10,599.2**	**314.7**	**204.8**	**106.1**
Personal consumption expenditures	**7,753.2**	**7,501.2**	**7,600.7**	**7,673.6**	**7,836.3**	**7,902.3**	**7,362.9**	**7,198.9**	**7,244.1**	**7,304.0**	**7,426.6**	**7,476.9**	**222.5**	**122.6**	**50.3**
Durable goods	**941.1**	**907.3**	**898.2**	**926.2**	**975.1**	**965.1**	**1,027.0**	**963.8**	**965.0**	**1,005.1**	**1,069.1**	**1,068.7**	**69.8**	**64.0**	**–.4**
Motor vehicles and parts	423.6	410.4	402.1	414.5	447.2	430.7	441.5	419.0	414.5	429.5	466.9	455.1	18.2	37.4	–11.8
Furniture and household equipment	334.1	325.3	321.8	329.9	339.9	344.8	400.2	373.5	374.7	391.7	412.4	422.2	35.5	20.7	9.8
Other	183.4	171.6	174.3	181.8	188.0	189.5	187.3	173.0	177.6	185.9	191.4	194.3	17.1	5.5	2.9
Nondurable goods	**2,209.4**	**2,119.2**	**2,175.7**	**2,170.8**	**2,230.0**	**2,261.3**	**2,120.8**	**2,061.8**	**2,090.5**	**2,096.9**	**2,134.3**	**2,161.5**	**77.2**	**37.4**	**27.2**
Food	1,064.4	1,016.4	1,037.4	1,049.7	1,074.9	1,095.5	995.0	963.9	979.6	985.4	1,002.8	1,012.1	36.8	17.4	9.3
Clothing and shoes	311.1	306.4	304.8	307.5	315.1	317.0	334.4	323.4	325.7	331.9	339.5	340.2	15.3	7.6	.7
Gasoline, fuel oil, and other energy goods	209.8	193.0	222.4	196.9	209.2	210.6	198.3	201.0	203.1	192.9	194.7	202.7	–1.0	1.8	8.0
Other	624.2	603.4	611.1	616.7	630.8	638.1	593.7	573.8	582.2	587.4	598.3	607.0	26.4	10.9	8.7
Services	**4,602.7**	**4,474.7**	**4,526.8**	**4,576.6**	**4,631.2**	**4,676.0**	**4,224.1**	**4,175.4**	**4,190.7**	**4,208.4**	**4,237.2**	**4,260.0**	**82.3**	**28.8**	**22.8**
Housing	1,198.6	1,167.7	1,181.5	1,191.4	1,204.9	1,216.6	1,085.6	1,071.7	1,078.0	1,082.8	1,088.7	1,093.1	23.7	5.9	4.4
Household operation	425.7	412.9	422.6	424.2	428.5	427.5	396.0	395.6	396.6	393.4	396.8	397.3	1.5	3.4	.5
Electricity and gas	164.0	156.0	163.1	163.9	165.8	163.1	144.9	147.9	148.0	143.1	144.5	144.1	–.3	1.4	–.4
Other household operation	261.7	256.9	259.5	260.3	262.7	264.4	251.2	247.6	248.5	250.5	252.4	253.4	2.0	1.9	1.0
Transportation	293.8	291.5	292.3	292.8	295.3	294.6	278.3	281.3	281.6	278.8	277.2	275.5	–6.5	–1.6	–1.7
Medical care	1,302.5	1,239.8	1,263.1	1,289.2	1,315.1	1,342.5	1,190.1	1,154.8	1,169.3	1,182.4	1,196.9	1,211.5	58.0	14.5	14.6
Recreation	319.2	309.7	312.6	317.2	321.3	325.7	291.1	287.5	287.5	290.1	291.9	294.8	6.3	1.8	2.9
Other	1,063.0	1,053.0	1,054.7	1,061.9	1,066.2	1,069.1	981.7	983.5	976.6	979.7	984.3	986.3	–1.5	4.6	2.0
Gross private domestic investment	**1,671.4**	**1,614.7**	**1,605.3**	**1,624.3**	**1,689.1**	**1,767.0**	**1,638.9**	**1,595.8**	**1,581.6**	**1,599.9**	**1,656.1**	**1,718.0**	**66.9**	**56.2**	**61.9**
Fixed investment	**1,672.3**	**1,594.6**	**1,606.2**	**1,630.1**	**1,699.5**	**1,753.3**	**1,634.6**	**1,573.5**	**1,577.7**	**1,601.4**	**1,661.0**	**1,698.3**	**68.8**	**59.6**	**37.3**
Nonresidential	1,109.7	1,074.3	1,071.8	1,086.9	1,124.4	1,155.5	1,124.6	1,088.9	1,087.3	1,105.8	1,139.5	1,165.9	32.0	33.7	26.4
Structures	258.3	256.3	256.1	259.2	259.8	258.0	236.6	239.0	236.5	238.8	237.7	233.4	–12.4	–1.1	–4.3
Equipment and software	851.4	817.9	815.8	827.7	864.6	897.5	893.6	853.9	855.0	871.6	907.7	940.1	46.9	36.1	32.4
Information processing equipment and software	463.8	424.1	436.2	451.2	477.0	490.8	522.7	468.2	487.2	506.4	537.7	559.4	63.4	31.3	21.7
Computers and peripheral equipment	97.2	84.9	86.8	93.5	101.8	106.8	.....	.....	.....	.....	.....	.....	.....	.....	.....
Software	181.2	169.8	173.4	177.6	185.1	188.5	182.5	169.7	174.4	178.6	185.0	191.9	15.0	6.4	6.9
Other	185.4	169.3	175.9	180.1	190.2	195.5	194.7	177.1	184.3	188.6	200.2	205.8	17.6	11.6	5.6
Industrial equipment	133.7	135.6	133.4	133.2	134.1	134.0	131.2	133.9	131.4	131.0	131.4	131.1	–4.9	.4	–.3
Transportation equipment	121.1	128.8	119.8	115.3	117.8	131.7	116.5	127.2	117.4	115.1	113.7	119.9	–11.7	–1.4	6.2
Other equipment	132.7	129.4	126.3	128.1	135.7	141.0	128.5	126.1	122.6	123.9	131.1	136.4	4.2	7.2	5.3
Residential	562.6	520.3	534.4	543.2	575.1	597.8	505.6	481.0	486.4	491.7	516.7	527.5	35.3	25.0	10.8
Change in private inventories	**–.9**	**20.2**	**–.9**	**–5.8**	**–10.5**	**13.7**	**.7**	**21.5**	**1.6**	**–4.5**	**–9.1**	**14.9**	**–5.0**	**–4.6**	**24.0**
Farm	–2.3	–4.8	.2	–2.7	–4.3	–2.3	–1.0	–3.5	1.2	–2.0	–2.8	–.6	2.3	–.8	2.2
Nonfarm	1.4	25.0	–1.2	–3.0	–6.2	16.0	2.0	25.4	.3	–2.4	–5.9	15.9	–7.3	–3.5	21.8
Net exports of goods and services	**–494.9**	**–476.1**	**–487.6**	**–505.5**	**–490.6**	**–495.9**	**–508.9**	**–511.5**	**–490.0**	**–526.0**	**–505.2**	**–514.4**	**–38.3**	**20.8**	**–9.2**
Exports	**1,049.0**	**1,017.2**	**1,021.0**	**1,020.2**	**1,048.5**	**1,106.3**	**1,035.0**	**1,017.5**	**1,012.4**	**1,009.6**	**1,033.7**	**1,084.1**	**20.8**	**24.1**	**50.4**
Goods	725.4	698.3	707.6	707.7	722.1	764.4	720.4	703.2	706.5	703.5	718.2	753.5	13.2	14.7	35.3
Services	323.6	318.8	313.3	312.5	326.4	341.9	314.3	314.0	305.7	305.9	315.2	330.3	7.5	9.3	15.1
Imports	**1,543.9**	**1,493.3**	**1,508.5**	**1,525.7**	**1,539.0**	**1,602.2**	**1,543.9**	**1,529.0**	**1,502.5**	**1,535.7**	**1,538.9**	**1,598.6**	**59.2**	**3.2**	**59.7**
Goods	1,283.2	1,240.8	1,254.2	1,272.4	1,275.6	1,330.7	1,308.5	1,288.1	1,266.2	1,307.4	1,302.4	1,357.8	60.1	–5.0	55.4
Services	260.6	252.5	254.3	253.3	263.5	271.5	236.4	241.2	236.5	229.8	237.2	242.1	0	7.4	4.9
Government consumption expenditures and gross investment	**2,055.7**	**1,983.9**	**2,017.4**	**2,054.2**	**2,072.1**	**2,079.0**	**1,899.5**	**1,870.8**	**1,869.0**	**1,902.8**	**1,911.1**	**1,915.1**	**62.6**	**8.3**	**4.0**
Federal	**757.6**	**710.0**	**723.0**	**764.7**	**769.6**	**773.1**	**704.7**	**675.8**	**675.5**	**712.0**	**714.3**	**717.1**	**56.7**	**2.3**	**2.8**
National defense	497.7	461.1	463.3	507.3	507.2	512.9	463.3	439.5	433.2	472.8	471.2	476.1	44.5	–1.6	4.9
Consumption expenditures	437.2	404.6	408.6	447.5	443.7	448.9	401.8	382.0	377.3	411.8	406.9	411.2	39.6	–4.9	4.3
Gross investment	60.5	56.6	54.7	59.8	63.5	64.0	61.6	57.4	55.7	60.8	64.5	65.1	5.0	3.7	.6
Nondefense	259.9	248.9	259.7	257.4	262.4	260.2	241.4	236.4	242.4	239.3	243.1	241.1	12.2	3.8	–2.0
Consumption expenditures	225.4	216.1	227.3	221.4	228.5	224.3	206.9	203.6	209.9	203.4	209.3	205.2	10.6	5.9	–4.1
Gross investment	34.5	32.7	32.4	36.0	33.8	35.9	34.5	32.7	32.4	36.0	33.8	36.0	1.6	–2.2	2.2
State and local	**1,298.1**	**1,273.9**	**1,294.5**	**1,289.6**	**1,302.5**	**1,305.8**	**1,195.3**	**1,195.3**	**1,193.8**	**1,191.4**	**1,197.4**	**1,198.6**	**6.2**	**6.0**	**1.2**
Consumption expenditures	1,045.3	1,024.2	1,045.8	1,040.9	1,046.3	1,048.2	956.8	956.4	957.8	956.6	956.0	956.7	6.3	–.6	.7
Gross investment	252.8	249.7	248.7	248.7	256.2	257.6	238.5	239.0	236.0	234.7	241.5	242.0	–.1	6.8	.5
Residual	.....	.....	.....	.....	.....	.....	–18.8	–2.5	–4.5	–11.5	–27.4	–31.7	.....	.....	.....
Addenda:															
Final sales of domestic product	10,986.3	10,603.6	10,736.7	10,852.4	11,117.4	11,238.7	10,393.4	10,138.9	10,206.4	10,289.5	10,497.7	10,580.0	316.5	208.2	82.3
Gross domestic purchases	11,480.3	11,099.9	11,223.4	11,352.2	11,597.5	11,748.3	10,903.2	10,668.0	10,697.6	10,809.9	10,995.4	11,109.9	351.7	185.5	114.5
Final sales to domestic purchasers	11,481.2	11,079.7	11,224.3	11,357.9	11,608.0	11,734.6	10,898.9	10,646.1	10,693.5	10,811.1	11,000.1	11,090.7	353.5	189.0	90.6
Gross domestic product	**10,985.5**	**10,623.7**	**10,735.8**	**10,846.7**	**11,107.0**	**11,252.3**	**10,397.7**	**10,160.8**	**10,210.4**	**10,288.3**	**10,493.1**	**10,599.2**	**314.7**	**204.8**	**106.1**
Plus: Income receipts from the rest of the world	.....	304.8	296.8	299.5	312.1	.....	.....	293.7	283.4	285.6	296.1	.....	.....	10.5	.....
Less: Income payments to the rest of the world	.....	266.9	269.0	266.2	274.3	.....	.....	256.1	256.4	253.8	260.7	.....	.....	6.9	.....
Equals: Gross national product	.....	**10,661.6**	**10,763.7**	**10,880.0**	**11,144.8**	.....	.....	**10,198.5**	**10,237.6**	**10,320.2**	**10,528.6**	.....	.....	**208.4**	.....
Net domestic product	9,677.7	9,323.3	9,430.1	9,543.3	9,797.9	9,939.4	9,088.1	8,858.4	8,903.4	8,983.4	9,181.7	9,283.7	289.6	198.3	102.0

r Revised.

NOTE.—Users are cautioned that particularly for components that exhibit rapid change in prices relative to other prices in the economy, the chained-dollar estimates should not be used to measure the component's relative importance or its contribution to the growth rate of more aggregate series. For accurate estimates of the contributions to percent changes in real gross domestic product, use table 2.

See "Explanatory Note" at the end of the tables.

Table 4.—Price Indexes for Gross Domestic Product and Related Measures: Percent Change From Preceding Period

	2001	2002	2003 r	Seasonally adjusted at annual rates															
				2000				2001				2002				2003			
				I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV r
Gross domestic product (GDP)	**2.4**	**1.5**	**1.7**	**3.4**	**2.0**	**1.9**	**1.8**	**3.2**	**3.2**	**1.6**	**1.6**	**1.1**	**1.5**	**1.5**	**1.7**	**2.3**	**1.1**	**1.6**	**1.2**
Personal consumption expenditures	**2.0**	**1.4**	**1.8**	**3.5**	**2.0**	**1.9**	**1.8**	**3.2**	**2.5**	**.5**	**.4**	**.7**	**2.9**	**2.0**	**1.7**	**2.8**	**.5**	**1.8**	**.7**
Durable goods	–1.9	–2.9	–3.7	–1.8	–.5	–2.5	–1.0	–1.3	–3.1	–2.8	–2.2	–3.5	–2.9	–3.0	–3.0	–4.4	–3.9	–4.0	–3.9
Nondurable goods	1.5	.5	2.1	5.2	3.7	3.4	1.4	1.3	3.7	–.9	–4.3	–.1	5.7	1.4	1.0	5.1	–2.1	3.8	.5
Services	3.2	2.7	2.9	3.9	1.7	2.1	2.6	5.1	3.2	1.8	3.3	2.0	2.8	3.4	3.1	3.2	2.7	2.0	1.7
Gross private domestic investment	**1.1**	**0**	**.9**	**2.0**	**1.2**	**1.9**	**.8**	**.3**	**1.3**	**2.3**	**0**	**–.7**	**–.7**	**–1.0**	**1.6**	**1.3**	**0**	**2.0**	**3.5**
Fixed investment	1.1	.1	1.1	2.3	1.2	1.9	.9	.1	1.6	2.4	0	–.8	–.7	–.7	1.7	1.9	0	2.1	3.7
Nonresidential	–.2	–.9	–.2	.6	.3	1.4	0	–1.8	.2	.6	–1.2	–1.3	–1.5	–1.5	.4	–.3	–1.2	1.6	1.7
Structures	5.5	1.4	2.0	4.8	3.6	4.5	5.0	6.5	6.9	6.3	1.2	–.9	.5	.3	1.1	3.8	1.1	2.7	4.7
Equipment and software	–2.2	–1.7	–.9	–.8	–.8	.4	–1.7	–4.7	–2.1	–1.6	–2.1	–1.4	–2.1	–2.1	.2	–1.6	–1.8	1.2	.9
Residential	4.6	2.4	3.9	7.1	3.9	3.2	3.4	5.3	5.1	7.0	2.9	.3	1.1	.9	4.5	6.4	2.2	3.1	7.5
Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Net exports of goods and services	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Exports	–.4	–.4	2.1	2.7	2.1	.9	.4	.1	–1.2	–2.1	–3.6	–1.2	2.9	3.3	.6	3.6	.8	1.6	2.4
Goods	–.7	–.7	2.0	1.3	1.6	.3	.4	–.1	–1.6	–2.6	–3.8	–1.4	2.1	3.3	.6	3.5	1.7	–.2	3.7
Services	.4	.3	2.2	6.2	3.5	2.5	.6	.6	–.3	–1.0	–3.0	–.9	4.6	3.2	.6	3.8	–1.3	5.7	–.3
Imports	–2.5	–1.0	3.6	5.9	.7	4.2	.7	–2.8	–6.0	–5.3	–9.8	–1.6	10.5	3.7	.8	11.7	–4.1	2.7	.9
Goods	–3.0	–1.7	2.9	6.8	1.2	4.5	.8	–3.7	–6.6	–6.6	–11.1	–2.1	10.7	2.7	.5	11.8	–6.8	2.6	.3
Services	.2	2.5	7.4	1.3	–2.0	2.5	.3	2.1	–3.0	1.4	–2.9	.7	9.3	8.6	2.0	11.3	10.4	3.3	3.8
Government consumption expenditures and gross investment	**2.6**	**2.6**	**2.9**	**6.6**	**1.7**	**4.5**	**2.7**	**2.7**	**2.2**	**2.0**	**1.4**	**3.6**	**3.3**	**2.2**	**1.8**	**7.3**	**.1**	**1.7**	**.5**
Federal	2.1	2.7	2.5	7.2	–1.1	5.0	1.6	2.0	1.6	2.4	1.7	5.9	2.3	1.2	–.5	7.7	1.4	1.3	.2
National defense	2.2	2.5	2.6	8.2	–.2	3.6	.9	3.6	1.6	2.4	.8	5.2	2.3	1.8	–.6	8.0	1.2	1.3	.4
Nondefense	1.9	3.2	2.3	5.4	–2.6	7.5	2.7	–.7	1.8	2.3	3.6	7.3	2.1	.2	–.4	7.2	1.6	1.3	0
State and local	2.9	2.5	3.1	6.3	3.2	4.2	3.2	3.0	2.5	1.8	1.3	2.4	3.8	2.7	3.0	7.1	–.7	2.0	.6
Addenda:																			
Final sales of domestic product	2.4	1.5	1.7	3.4	2.0	1.9	1.8	3.1	3.2	1.6	1.6	1.1	1.4	1.5	1.8	2.4	1.1	1.6	1.2
Gross domestic purchases	2.0	1.4	1.9	3.8	1.8	2.3	1.8	2.6	2.3	1.0	.5	1.0	2.4	1.6	1.7	3.4	.4	1.8	1.1
Final sales to domestic purchasers	2.0	1.4	1.9	3.8	1.8	2.3	1.8	2.6	2.3	1.0	.5	.9	2.4	1.6	1.7	3.5	.4	1.8	1.1
Gross national product (GNP)	2.4	1.5	.....	3.3	2.0	1.9	1.8	3.2	3.1	1.6	1.6	1.1	1.5	1.5	1.7	2.3	1.1	1.7	.....
Implicit price deflators:																			
GDP	2.4	1.5	1.6	3.6	1.7	2.1	1.6	3.1	3.2	1.6	1.9	.7	1.9	1.0	1.8	2.3	1.1	1.6	1.2
Gross domestic purchases	2.0	1.4	1.9	4.1	1.6	2.5	1.6	2.6	2.3	1.0	.8	.6	2.9	1.2	1.8	3.4	.4	1.8	1.0
GNP	2.4	1.5	.....	3.6	1.7	2.1	1.6	3.1	3.2	1.6	1.9	.7	2.0	1.0	1.8	2.3	1.1	1.6	.....

r Revised.
See "Explanatory Note" at the end of the tables.

Table 5.—Real Gross Domestic Product, Quantity Indexes

[Index numbers, 2000=100]

	2001	2002	2003 r	Seasonally adjusted				
				2002	2003			
				IV	I	II	III	IV r
Gross domestic product	**100.506**	**102.710**	**105.916**	**103.502**	**104.008**	**104.801**	**106.887**	**107.968**
Personal consumption expenditures	**102.452**	**105.951**	**109.251**	**106.819**	**107.489**	**108.378**	**110.197**	**110.943**
Durable goods	104.144	110.868	118.957	111.638	111.779	116.420	123.834	123.793
Nondurable goods	101.852	104.949	108.913	105.885	107.358	107.685	109.607	111.003
Services	102.382	105.420	107.515	106.276	106.664	107.115	107.849	108.430
Gross private domestic investment	**91.650**	**90.580**	**94.435**	**91.953**	**91.135**	**92.186**	**95.424**	**98.996**
Fixed investment	96.826	93.258	97.357	93.718	93.968	95.378	98.932	101.149
Nonresidential	95.517	88.683	91.278	88.378	88.248	89.751	92.485	94.630
Structures	97.465	79.492	75.547	76.304	75.523	76.244	75.906	74.514
Equipment and software	94.825	92.144	97.246	92.927	93.047	94.851	98.779	102.309
Residential	100.351	105.228	113.124	107.629	108.828	110.021	115.616	118.031
Change in private inventories								
Exports of goods and services	**94.773**	**92.512**	**94.409**	**92.818**	**92.353**	**92.097**	**94.290**	**98.893**
Imports of goods and services	**97.377**	**100.609**	**104.617**	**103.610**	**101.810**	**104.059**	**104.277**	**108.322**
Government consumption expenditures and gross investment	**102.750**	**106.697**	**110.334**	**108.666**	**108.563**	**110.527**	**111.008**	**111.240**
Federal	103.746	111.958	121.761	116.764	116.713	123.025	123.406	123.900
State and local	102.248	104.047	104.592	104.593	104.463	104.248	104.779	104.880
Addenda:								
Final sales of domestic product	101.441	103.242	106.484	103.877	104.569	105.420	107.553	108.396
Gross domestic purchases	100.672	103.482	106.932	104.625	104.915	106.016	107.836	108.959
Final sales to domestic purchasers	101.575	103.998	107.484	104.992	105.459	106.619	108.483	109.376
Gross national product	100.462	102.527		103.476	103.873	104.711	106.825	

r Revised.
See "Explanatory Note" at the end of the tables.

Table 6.—Price Indexes for Gross Domestic Product

[Index numbers, 2000=100]

	2001	2002	2003 r	Seasonally adjusted				
				2002	2003			
				IV	I	II	III	IV r
Gross domestic product	**102.376**	**103.949**	**105.665**	**104.571**	**105.163**	**105.440**	**105.870**	**106.187**
Personal consumption expenditures	**102.039**	**103.429**	**105.302**	**104.203**	**104.927**	**105.065**	**105.522**	**105.695**
Durable goods	98.086	95.208	91.682	94.136	93.074	92.147	91.207	90.298
Nondurable goods	101.530	102.075	104.180	102.789	104.079	103.529	104.488	104.623
Services	103.168	105.946	108.966	107.174	108.028	108.758	109.306	109.771
Gross private domestic investment	**101.070**	**101.119**	**102.062**	**101.259**	**101.586**	**101.589**	**102.093**	**102.981**
Fixed investment	101.087	101.155	102.291	101.341	101.808	101.796	102.319	103.241
Nonresidential	99.770	98.859	98.664	98.658	98.579	98.293	98.678	99.106
Structures	105.518	106.974	109.165	107.274	108.268	108.559	109.288	110.547
Equipment and software	97.786	96.121	95.270	95.781	95.404	94.961	95.251	95.464
Residential	104.628	107.105	111.257	108.184	109.881	110.485	111.321	113.343
Change in private inventories								
Exports of goods and services	**99.628**	**99.273**	**101.342**	**99.964**	**100.842**	**101.044**	**101.434**	**102.049**
Imports of goods and services	**97.537**	**96.519**	**100.030**	**97.694**	**100.435**	**99.381**	**100.042**	**100.261**
Government consumption expenditures and gross investment	**102.587**	**105.207**	**108.229**	**106.055**	**107.951**	**107.966**	**108.433**	**108.564**
Federal	102.065	104.858	107.501	105.066	107.032	107.399	107.755	107.818
State and local	102.853	105.382	108.603	106.580	108.435	108.246	108.778	108.951
Addenda:								
Final sales of domestic product	102.381	103.955	105.702	104.585	105.198	105.474	105.906	106.228
Gross domestic purchases	101.974	103.374	105.308	104.065	104.934	105.031	105.496	105.772
Final sales to domestic purchasers	101.978	103.379	105.343	104.077	104.968	105.062	105.531	105.811
Gross national product	102.372	103.936		104.556	105.156	105.438	105.872	
Implicit price deflators:								
Gross domestic product	102.373	103.945	105.652	104.556	105.146	105.427	105.851	106.162
Final sales of domestic product	102.381	103.955	105.705	104.583	105.196	105.471	105.904	106.226
Gross domestic purchases	101.971	103.370	105.293	104.048	104.915	105.017	105.476	105.745
Final sales to domestic purchasers	101.978	103.379	105.343	104.072	104.964	105.058	105.526	105.806
Gross national product	102.368	103.932		104.541	105.138	105.425	105.853	

r Revised.
See "Explanatory Note" at the end of the tables.

Table 7.—Real Gross Domestic Product: Percent Change From Preceding Year

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003 r
Gross domestic product (GDP)	**4.1**	**3.5**	**1.9**	**–0.2**	**3.3**	**2.7**	**4.0**	**2.5**	**3.7**	**4.5**	**4.2**	**4.5**	**3.7**	**0.5**	**2.2**	**3.1**
Personal consumption expenditures	**4.1**	**2.8**	**2.0**	**.2**	**3.3**	**3.3**	**3.7**	**2.7**	**3.4**	**3.8**	**5.0**	**5.1**	**4.7**	**2.5**	**3.4**	**3.1**
Durable goods	6.0	2.2	–.3	–5.6	5.9	7.8	8.4	4.4	7.8	8.6	11.3	11.7	7.3	4.1	6.5	7.3
Nondurable goods	3.3	2.8	1.6	–.2	2.0	2.7	3.5	2.2	2.6	2.7	4.0	4.6	3.8	1.9	3.0	3.8
Services	4.0	3.0	2.9	1.7	3.5	2.8	2.9	2.6	2.9	3.3	4.2	4.0	4.5	2.4	3.0	2.0
Gross private domestic investment	**2.4**	**4.0**	**–3.4**	**–8.1**	**8.1**	**8.9**	**13.6**	**3.1**	**8.9**	**12.4**	**9.8**	**7.8**	**5.7**	**–8.4**	**–1.2**	**4.3**
Fixed investment	3.3	3.0	–2.1	–6.5	5.9	8.6	9.3	6.5	9.0	9.2	10.2	8.3	6.5	–3.2	–3.7	4.4
Nonresidential	5.2	5.6	.5	–5.4	3.2	8.7	9.2	10.5	9.3	12.1	11.1	9.2	8.7	–4.5	–7.2	2.9
Structures	.6	2.0	1.5	–11.1	–6.0	–.7	1.8	6.4	5.6	7.3	5.1	–.4	6.8	–2.5	–18.4	–5.0
Equipment and software	7.5	7.3	0	–2.6	7.3	12.5	11.9	12.0	10.6	13.8	13.3	12.7	9.4	–5.2	–2.8	5.5
Residential	–1.0	–3.0	–8.6	–9.6	13.8	8.2	9.6	–3.2	8.0	1.9	7.6	6.0	.8	.4	4.9	7.5
Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Net exports of goods and services	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Exports	16.0	11.5	9.0	6.6	6.9	3.2	8.7	10.1	8.4	11.9	2.4	4.3	8.7	–5.2	–2.4	2.1
Goods	18.8	11.9	8.4	6.9	7.5	3.3	9.7	11.7	8.8	14.3	2.2	3.8	11.2	–6.1	–4.0	1.9
Services	9.0	10.3	10.5	6.0	5.5	3.2	6.3	6.3	7.2	5.9	2.9	5.6	2.9	–3.1	1.4	2.4
Imports	3.9	4.4	3.6	–.6	7.0	8.8	11.9	8.0	8.7	13.6	11.6	11.5	13.1	–2.6	3.3	4.0
Goods	4.0	4.3	3.0	–.1	9.3	10.1	13.3	9.0	9.3	14.4	11.7	12.4	13.5	–3.2	3.7	4.8
Services	3.4	4.9	6.5	–2.6	–2.6	2.9	5.7	3.3	5.5	9.4	11.4	6.9	11.1	.4	1.4	0
Government consumption expenditures and gross investment	**1.3**	**2.6**	**3.2**	**1.1**	**.5**	**–.9**	**0**	**.5**	**1.0**	**1.9**	**1.9**	**3.9**	**2.1**	**2.8**	**3.8**	**3.4**
Federal	–1.6	1.5	2.0	–.2	–1.7	–4.2	–3.7	–2.7	–1.2	–1.0	–1.1	2.2	.9	3.7	7.9	8.8
National defense	–.5	–.5	0	–1.1	–5.0	–5.6	–4.9	–3.8	–1.4	–2.8	–2.1	1.9	–.5	3.9	8.9	10.6
Nondefense	–5.1	8.3	8.3	2.4	6.9	–.7	–1.2	–.4	–.7	2.6	.7	2.8	3.5	3.5	6.2	5.3
State and local	3.7	3.4	4.1	2.1	2.2	1.4	2.6	2.6	2.3	3.6	3.6	4.7	2.7	2.2	1.8	.5
Addenda:																
Final sales of domestic product	4.3	3.4	2.1	.1	3.0	2.6	3.4	3.0	3.7	4.0	4.2	4.5	3.8	1.4	1.8	3.1
Gross domestic purchases	3.2	3.0	1.4	–.8	3.3	3.2	4.4	2.4	3.8	4.8	5.3	5.3	4.4	.7	2.8	3.3
Final sales to domestic purchasers	3.4	2.8	1.6	–.6	3.1	3.2	3.8	2.8	3.8	4.3	5.3	5.4	4.5	1.6	2.4	3.4
Gross national product	4.2	3.5	2.0	–.3	3.3	2.7	3.9	2.6	3.7	4.4	4.0	4.6	3.7	.5	2.1	.....
Real disposable personal income	4.3	2.8	1.9	.5	3.4	1.0	2.7	2.8	3.0	3.5	5.8	3.0	4.8	1.8	3.8	2.5
Price indexes:																
Gross domestic purchases	3.4	3.8	4.1	3.3	2.3	2.2	2.1	2.1	1.8	1.4	.6	1.6	2.5	2.0	1.4	1.9
Gross domestic purchases excluding food and energy	3.7	3.6	3.7	3.5	2.6	2.3	2.2	2.2	1.5	1.3	1.0	1.4	1.9	1.9	1.7	1.4
GDP	3.4	3.8	3.9	3.5	2.3	2.3	2.1	2.0	1.9	1.7	1.1	1.4	2.2	2.4	1.5	1.7
GDP excluding food and energy	3.4	3.6	3.7	3.6	2.5	2.4	2.2	2.1	1.7	1.7	1.2	1.5	2.0	2.1	1.8	1.4
Personal consumption expenditures	4.0	4.4	4.6	3.6	2.9	2.3	2.1	2.1	2.2	1.7	.9	1.7	2.5	2.0	1.4	1.8

r revised

Table 8.—Real Gross Domestic Product: Percent Change From Quarter One Year Ago

	2000				2001				2002				2003			
	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV r
Gross domestic product (GDP)	**4.1**	**4.8**	**3.5**	**2.2**	**1.9**	**0.2**	**0**	**0**	**1.2**	**1.8**	**3.0**	**2.8**	**2.1**	**2.4**	**3.6**	**4.3**
Personal consumption expenditures	**5.5**	**4.6**	**4.5**	**4.1**	**2.6**	**2.5**	**2.0**	**2.7**	**3.6**	**3.7**	**3.7**	**2.7**	**2.3**	**2.5**	**3.7**	**3.9**
Durable goods	13.7	5.9	5.2	4.7	–.4	4.5	3.2	9.4	9.3	7.0	8.1	1.8	1.5	5.6	11.0	10.9
Nondurable goods	3.7	4.1	4.3	3.0	3.0	1.3	1.5	1.7	3.1	3.5	2.8	2.8	2.7	2.9	4.7	4.8
Services	4.7	4.5	4.4	4.5	3.1	2.7	2.0	1.8	2.6	3.1	3.2	2.9	2.3	1.7	1.9	2.0
Gross private domestic investment	**4.4**	**11.2**	**5.8**	**1.4**	**.3**	**–10.1**	**–9.7**	**–13.5**	**–8.6**	**–3.3**	**1.6**	**6.5**	**2.8**	**2.8**	**3.6**	**7.7**
Fixed investment	7.8	7.7	5.5	5.1	1.6	–3.0	–4.2	–7.0	–7.0	–4.6	–3.1	.2	1.1	2.4	6.1	7.9
Nonresidential	9.4	9.9	7.9	7.8	3.1	–4.0	–6.5	–10.2	–10.8	–8.2	–6.4	–2.8	–1.2	1.3	4.6	7.1
Structures	2.7	6.3	9.6	8.8	5.3	–.4	–2.1	–12.4	–17.0	–19.0	–22.6	–14.9	–9.8	–5.3	–1.9	–2.3
Equipment and software	11.7	11.1	7.3	7.5	2.4	–5.2	–8.2	–9.4	–8.5	–4.0	.1	1.6	1.8	3.4	6.7	10.1
Residential	3.7	1.9	–.7	–1.9	–2.2	–.4	2.4	1.7	3.2	4.4	4.7	7.1	6.1	5.0	9.2	9.7
Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Net exports of goods and services	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Exports	8.2	10.2	10.1	6.5	3.7	–2.8	–9.8	–11.5	–9.5	–4.2	1.6	3.3	1.7	–.7	.6	6.5
Goods	10.2	12.6	13.7	8.5	4.8	–3.5	–12.2	–12.7	–12.1	–4.9	1.2	.8	2.0	–1.3	–.3	7.2
Services	3.6	4.5	1.6	1.8	.9	–1.3	–3.5	–8.3	–3.0	–2.5	2.6	9.3	1.1	.7	2.6	5.2
Imports	13.6	14.0	13.8	11.2	5.2	–.9	–6.8	–7.4	–4.0	2.2	6.2	9.4	5.3	3.5	2.6	4.5
Goods	14.3	14.6	14.1	11.3	5.3	–2.1	–7.5	–7.9	–4.8	3.3	7.1	9.9	6.4	4.6	2.9	5.4
Services	10.1	11.1	12.4	10.6	4.7	5.1	–3.3	–4.5	.5	–3.3	1.9	6.7	.2	–1.8	1.2	.4
Government consumption expenditures and gross investment	**2.7**	**3.5**	**1.7**	**.4**	**2.6**	**2.7**	**2.1**	**3.6**	**3.3**	**2.9**	**4.6**	**4.5**	**3.3**	**4.1**	**3.9**	**2.4**
Federal	.9	4.6	.3	–2.2	3.8	1.4	3.6	6.3	6.2	7.1	8.2	10.1	7.9	10.9	10.2	6.1
National defense	–.4	3.6	–1.6	–3.5	4.4	1.0	3.6	6.6	6.8	8.5	9.1	10.9	7.2	14.4	12.7	8.3
Nondefense	3.4	6.3	3.9	.3	2.7	2.0	3.5	5.7	5.1	4.6	6.5	8.7	9.2	4.7	5.6	2.0
State and local	3.6	2.9	2.4	1.7	2.0	3.3	1.4	2.3	1.9	.8	2.8	1.6	.8	.5	.5	.3
Addenda:																
Final sales of domestic product	4.6	4.2	3.5	2.9	2.2	1.5	1.0	1.1	1.4	1.6	2.2	1.8	1.9	2.4	4.0	4.4
Gross domestic purchases	4.9	5.5	4.2	3.0	2.2	.3	0	.1	1.6	2.5	3.5	3.6	2.6	2.8	3.8	4.1
Final sales to domestic purchasers	5.4	4.9	4.2	3.6	2.4	1.6	1.0	1.3	1.8	2.2	2.8	2.7	2.3	2.8	4.1	4.2
Gross national product	4.1	4.8	3.5	2.4	1.8	.1	–.2	.2	1.1	1.6	3.1	2.4	2.2	2.7	3.8	.....
Real disposable personal income	4.4	4.9	5.7	4.4	2.0	1.0	2.6	1.3	4.0	5.4	2.2	3.5	1.6	1.7	3.5	3.4
Price indexes:																
Gross domestic purchases	2.6	2.5	2.5	2.4	2.1	2.3	1.9	1.6	1.2	1.2	1.4	1.7	2.3	1.8	1.8	1.6
Gross domestic purchases excluding food and energy	1.9	1.8	1.9	1.8	1.7	1.8	1.9	2.1	1.8	1.7	1.6	1.4	1.6	1.4	1.3	1.3
GDP	2.1	2.1	2.3	2.2	2.2	2.5	2.4	2.4	1.9	1.4	1.4	1.4	1.7	1.6	1.7	1.5
GDP excluding food and energy	2.1	2.0	2.1	2.0	1.8	2.0	2.1	2.3	2.1	1.9	1.8	1.5	1.6	1.4	1.3	1.2
Personal consumption expenditures	2.7	2.5	2.4	2.3	2.2	2.3	2.0	1.6	1.0	1.1	1.5	1.8	2.4	1.8	1.7	1.4

r revised.

Table 9.—Relation of Gross Domestic Product, Gross National Product, and National Income

[Billions of dollars]

	2001	2002	2003 r	Seasonally adjusted at annual rates				
				2002	2003			
				IV	I	II	III	IV r
Gross domestic product	**10,100.8**	**10,480.8**	**10,985.5**	**10,623.7**	**10,735.8**	**10,846.7**	**11,107.0**	**11,252.3**
Plus: Income receipts from the rest of the world	319.0	299.1	.....	304.8	296.8	299.5	312.1	.....
Less: Income payments to the rest of the world	283.8	277.6	.....	266.9	269.0	266.2	274.3	.....
Equals: Gross national product	**10,135.9**	**10,502.3**	.....	**10,661.6**	**10,763.7**	**10,880.0**	**11,144.8**	.....
Less: Consumption of fixed capital	1,266.9	1,288.6	1,307.8	1,300.4	1,305.7	1,303.4	1,309.1	1,312.9
Less: Statistical discrepancy	−112.2	−77.2	.....	−15.7	23.2	−8.3	54.0	.....
Equals: National income	**8,981.2**	**9,290.8**	.....	**9,376.9**	**9,434.8**	**9,584.9**	**9,781.7**	.....
Compensation of employees	5,940.4	6,019.1	6,187.9	6,058.0	6,115.8	6,164.8	6,213.6	6,257.2
Wage and salary accruals	4,942.9	4,974.6	5,086.6	4,999.1	5,034.6	5,070.8	5,104.1	5,136.8
Supplements to wages and salaries	997.6	1,044.5	1,101.3	1,058.8	1,081.2	1,093.9	1,109.6	1,120.4
Proprietors' income with inventory valuation and capital consumption adjustments	770.6	797.7	847.3	812.2	813.5	838.8	860.9	875.9
Rental income of persons with capital consumption adjustment	163.1	173.0	163.7	159.0	163.2	153.4	157.0	181.0
Corporate profits with inventory valuation and capital consumption adjustments	770.4	904.2	.....	934.9	927.1	1,022.8	1,124.2	.....
Net interest and miscellaneous payments	568.4	582.4	580.7	589.7	589.3	581.7	579.9	571.7
Taxes on production and imports less subsidies	674.5	721.8	740.7	732.8	729.4	725.2	745.2	763.1
Business current transfer payments	92.5	89.8	95.2	86.2	90.1	92.5	97.1	101.2
Current surplus of government enterprises	1.2	2.8	5.0	4.1	6.3	5.8	3.7	4.2
Addendum:								
Gross domestic income	10,213.0	10,558.0	.....	10,639.4	10,712.7	10,855.0	11,053.0	.....

r Revised.

Table 10.—Personal Income and Its Disposition

[Billions of dollars]

	2001	2002	2003 r	Seasonally adjusted at annual rates				
				2002	2003			
				IV	I	II	III	IV r
Personal income [1]	**8,713.1**	**8,910.3**	**9,191.6**	**8,981.3**	**9,048.7**	**9,145.9**	**9,242.5**	**9,329.3**
Compensation of employees, received	5,940.4	6,019.1	6,187.9	6,058.0	6,114.4	6,166.2	6,213.6	6,257.2
Wage and salary disbursements	4,942.9	4,974.6	5,086.6	4,999.1	5,033.2	5,072.2	5,104.1	5,136.8
Supplements to wages and salaries	997.6	1,044.5	1,101.3	1,058.8	1,081.2	1,093.9	1,109.6	1,120.4
Proprietors' income with inventory valuation and capital consumption adjustments	770.6	797.7	847.3	812.2	813.5	838.8	860.9	875.9
Farm	25.0	14.3	19.5	16.3	13.0	20.0	21.5	23.4
Nonfarm	745.6	783.4	827.8	795.9	800.5	818.8	839.4	852.4
Rental income of persons with capital consumption adjustment	163.1	173.0	163.7	159.0	163.2	153.4	157.0	181.0
Personal income receipts on assets	1,374.9	1,378.5	1,390.5	1,392.0	1,388.6	1,390.2	1,389.2	1,394.2
Personal interest income	1,003.7	982.4	961.8	981.2	970.6	964.9	957.0	954.7
Personal dividend income	371.2	396.2	428.7	410.8	418.0	425.3	432.2	439.5
Personal current transfer receipts	1,192.6	1,292.2	1,377.2	1,315.6	1,337.6	1,369.7	1,398.7	1,402.8
Less: Contributions for government social insurance	728.5	750.3	774.9	755.5	768.7	772.3	776.9	781.7
Less: Personal current taxes	1,243.7	1,053.1	988.7	1,045.6	1,009.4	1,000.2	936.0	1,009.4
Equals: Disposable personal income	**7,469.4**	**7,857.2**	**8,202.9**	**7,935.6**	**8,039.2**	**8,145.8**	**8,306.6**	**8,320.0**
Less: Personal outlays	7,342.2	7,674.0	8,037.3	7,789.2	7,888.3	7,956.7	8,118.5	8,185.5
Equals: Personal saving	**127.2**	**183.2**	**165.6**	**146.4**	**151.0**	**189.0**	**188.1**	**134.4**
Personal saving as a percentage of disposable personal income	1.7	2.3	2.0	1.8	1.9	2.3	2.3	1.6
Addendum:								
Disposable personal income, billions of chained (2000) dollars [2]	7,320.2	7,596.7	7,789.9	7,615.8	7,662.0	7,753.5	7,872.3	7,872.0

r Revised.

1. Personal income is also equal to national income less corporate profits with inventory valuation and capital consumption adjustments, taxes on production and imports less subsidies, contributions for government social insurance, net interest and miscellaneous payments, business current transfer payments, current surplus of government enterprises, and wage accruals less disbursements, plus personal income receipts on assets, and personal current transfer receipts.

2. Equals disposable personal income deflated by the implicit price deflator for personal consumption expenditures.

Appendix Table A.—Real Gross Domestic Product and Related Aggregates and Price Indexes: Percent Change From Preceding Period

	2001	2002	2003 r	Seasonally adjusted at annual rates															
				2000				2001				2002				2003			
				I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV r
Gross domestic product (GDP) and related aggregates:																			
GDP	0.5	2.2	3.1	1.0	6.4	–0.5	2.1	–0.2	–0.6	–1.3	2.0	4.7	1.9	3.4	1.3	2.0	3.1	8.2	4.1
Goods	–2.0	2.1	4.4	–2.4	10.5	–3.3	.2	–3.4	–6.0	–4.1	4.1	7.7	–1.1	6.5	–2.8	4.3	2.2	18.3	7.8
Services	2.3	3.1	2.6	2.5	4.8	1.5	3.6	1.6	1.9	1.4	2.9	3.9	4.2	2.4	3.5	1.0	3.6	2.1	2.3
Structures	–.4	–3.0	2.4	5.9	1.6	–.7	.4	1.0	4.0	–6.4	–9.6	–1.0	–1.1	–1.4	2.1	–.3	2.8	13.9	2.6
Motor vehicle output	–4.8	11.4	2.6	5.2	–14.7	–18.1	–12.6	–14.6	19.1	1.5	30.2	11.3	5.5	10.8	–4.9	–6.4	2.1	26.6	2.9
GDP excluding motor vehicle output	.7	1.9	3.1	.9	7.4	.3	2.7	.3	–1.3	–1.4	1.1	4.5	1.8	3.1	1.5	2.3	3.1	7.6	4.2
Final sales of computers [1]	13.6	11.1	40.9	62.4	49.6	9.2	18.6	52.2	–17.1	–17.9	27.2	5.0	6.6	50.9	34.8	34.6	32.8	93.4	31.5
GDP excluding final sales of computers	.4	2.1	2.8	.5	6.0	–.6	1.9	–.7	–.4	–1.1	1.8	4.7	1.8	3.0	1.0	1.7	2.8	7.6	3.9
Farm gross value added [2]	–4.2	1.9	3.2	65.1	5.2	4.8	–18.2	–2.0	–15.8	–16.6	100.1	–64.2	94.9	50.5	–1.5	–39.5	59.0	–3.2	–16.6
Nonfarm business gross value added [3]	.1	2.3	3.7	–.1	7.5	–.8	2.2	–.8	–1.0	–2.5	1.6	6.7	.8	4.0	1.6	2.4	3.8	10.4	4.1
Price indexes:																			
GDP	2.4	1.5	1.7	3.4	2.0	1.9	1.8	3.2	3.2	1.6	1.6	1.1	1.5	1.5	1.7	2.3	1.1	1.6	1.2
GDP excluding food and energy	2.1	1.8	1.4	3.0	1.6	1.7	1.7	2.3	2.3	2.1	2.6	1.4	1.6	1.5	1.6	1.7	.7	1.3	1.1
GDP excluding final sales of computers	2.7	1.8	1.8	3.6	2.2	2.1	1.9	3.7	3.4	1.8	1.8	1.4	1.6	1.7	1.9	2.5	1.2	1.8	1.3
Gross domestic purchases	2.0	1.4	1.9	3.8	1.8	2.3	1.8	2.6	2.3	1.0	.5	1.0	2.4	1.6	1.7	3.4	.4	1.8	1.1
Gross domestic purchases excluding food and energy	1.9	1.7	1.4	2.9	1.3	1.6	1.4	2.3	2.0	1.9	2.3	1.2	1.5	1.5	1.5	1.8	.9	1.3	1.2
Gross domestic purchases excluding final sales of computers to domestic purchasers	2.3	1.6	2.1	4.0	2.1	2.5	2.0	3.2	2.6	1.3	.8	1.2	2.6	1.8	2.0	3.6	.5	2.0	1.2
Personal consumption expenditures	2.0	1.4	1.8	3.5	2.0	1.9	1.8	3.2	2.5	.5	.4	.7	2.9	2.0	1.7	2.8	.5	1.8	.7
Personal consumption expenditures excluding food and energy	1.9	1.7	1.2	2.4	1.3	.9	1.5	2.8	1.9	1.3	2.5	1.0	1.9	2.0	1.5	.9	.8	1.0	.7

r Revised.
1. For some components of final sales of computers, includes computer parts.
2. Farm output less intermediate goods and services purchased.
3. Consists of GDP less gross value added of farm, of households and institutions, and of general government.
See "Explanatory Note" at the end of the tables.

Explanatory Note: NIPA Measures of Quantities and Prices

Current-dollar GDP is a measure of the market value of goods, services, and structures produced in the economy in a particular period. Changes in current-dollar GDP can be decomposed into quantity and price components. Quantities, or "real" measures, and prices are expressed as index numbers with the reference year -- at present, the year 2000 -- equal to 100.

Annual changes in quantities and prices are calculated using a Fisher formula that incorporates weights from two adjacent years. (Quarterly changes in quantities and prices are calculated using a Fisher formula that incorporates weights from two adjacent quarters; quarterly indexes are adjusted for consistency to the annual indexes before percent changes are calculated.) For example, the 2001-02 annual percent change in real GDP uses prices for 2001 and 2002 as weights, and the 2001-02 annual percent change in GDP prices uses quantities for 2001 and 2002 as weights. These annual changes are "chained" (multiplied) together to form time series of quantity and price indexes. Percent changes in Fisher indexes are not affected by the choice of reference year. (BEA also publishes a measure of the price level known as the implicit price deflator (IPD), which is calculated as the ratio of the current-dollar value to the corresponding chained-dollar value, multiplied by 100. The values of the IPD are very close to the values of the corresponding "chain-type" price index.)

Index numbers of quantity and price indexes for GDP and its major components are presented in this release in tables 5 and 6. Percent changes from the preceding period are presented in tables 1, 4, 7, and 8. Contributions by major components to changes in real GDP are presented in table 2.

Measures of real GDP and its major components are also presented in dollar-denominated form, designated "chained (2000) dollar estimates." For most series, these estimates, which are presented in table 3, are computed by multiplying the current-dollar value in 2000 by a corresponding quantity index number and then dividing by 100. For example, if a current-dollar GDP component equaled $100 in 2000 and if real output for this component increased 10 percent in 2001, then the chained (2000) dollar value of this component in 2001 would be $110 (= $100 x 110 / 100). Percent changes calculated from chained-dollar estimates and from chain-type quantity indexes are the same; any differences will be small and due to rounding.

Chained-dollar values for the detailed GDP components will not necessarily sum to the chained-dollar estimate of GDP (or to any intermediate aggregate). This is because the relative prices used as weights for any period other than the reference year differ from those of the reference year. A measure of the extent of such differences is provided by a "residual" line, which indicates the difference between GDP (or other major aggregate) and the sum of the most detailed components in the table. For periods close to the reference year, when there usually has not been much change in the relative prices that are used as weights, the residuals tend to be small, and the chained-dollar estimates can be used to approximate the contributions to growth and to aggregate the detailed estimates. For periods further from the reference year, the residuals tend to be larger, and the chained-dollar estimates are less useful for analyses of contributions to growth. Thus, the contributions to percent change shown in table 2 provide a better measure of the composition of GDP growth. In particular, for components for which relative prices are changing rapidly, calculation of contributions using chained-dollar estimates may be misleading even just a few years from the reference year.

Reference: "Chained-Dollar Indexes: Issues, Tips on Their Use, and Upcoming Changes," November 2003 *Survey*, pp. 8-16.

PROOF OF SERVICE

I hereby certify that on March 4, 2004 I served, by electronic and U.S. mail, the Opening Brief of The California Independent System Operator Corporation to the parties in Docket # A.02-09-043.

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